DRAFT REPORT REVISION 3

VIWAPA IRP REPORT

BLACK & VEATCH PROJECT NO. 186089

PREPARED FOR

Virgin Islands Water and Power Authority

14 NOVEMBER 2016

Assumptions and Limitations Disclaimer

This report was prepared for the U.S. Virgin Islands Water and Power Authority by Black & Veatch Management Consulting, LLC (Black & Veatch) and is based on information not within the control of Black & Veatch. Black & Veatch has assumed that the information both verbal and written, provided by others is complete and correct; however, Black & Veatch does not guarantee the accuracy of the information, data, or opinions contained herein.

Any information shared with the Company prior to the release of the report is superseded by the Report.

Black & Veatch owes no duty of care to any third party and none is created by this report. Use of this report, or any information contained therein, by a third party shall be at the risk of such party and constitutes a waiver and release of Black & Veatch, its directors, officers, partners, employees and agents by such third party from and against all claims and liability, including, but not limited to, claims for breach of contract, breach of warranty, strict liability, negligence, negligent misrepresentation, and/or otherwise, and liability for special, incidental, indirect, or consequential damages, in connection with such use.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

1 Executive Summary

This report (Report) presents an Integrated Resource Plan (IRP) prepared for the US Virgin Islands Water and Power Authority (VIWAPA), whose service territory includes the islands of St. Thomas, St. Croix and St. John. The IRP provides an assessment of the future electric energy needs of the US Virgin Island's customers over the next 20 years and summarizes the preferred plan for meeting those needs in a safe, reliable, cost-effective and environmentally responsible manner. The preferred plan includes energy efficiency program offerings, retirement of all existing thermal capacity and installation of higher efficiency reciprocating and micro turbine technologies fueled by cleaner-burning liquid propane and sized more appropriately to provide greater system reliability and greater penetration of diverse, renewable energy technologies.

Integrated resource planning is a formal process undertaken by a utility to determine future resource requirements necessary for meeting forecasted annual peak and energy demand, with an adequate reserve to provide for system reliability and integrity. Utilities are frequently required by state legislation or regulation to undertake planning efforts that are then reviewed by state public utilities or service commissions.

IRPs are economically developed and evaluated; they utilize economic analyses and methodologies to assess various scenarios and sensitivities to arrive at an *economically* optimal plan. The optimal economic plan may or may not reflect the same conclusions that a pure financial analysis might conclude, since financial factors such as borrowing costs, capital structure, timing of cash flows and earnings are excluded from the economic evaluation process. Thus, incorporation of financial metrics into the economic results may result in modifications to the structure, timing, and design of the preferred or recommended plan.

IRPs have many benefits to consumers as well as positive impacts on the environment since the planning process produces results that, if correctly implemented, provides the lowest cost resource plan for which a utility can deliver reliable energy service to its customers. IRPs differ from traditional resource planning in that it requires the use of sophisticated analytical tools capable of evaluating and comparing the costs and benefits of supply and demand resources as well as the integration of utility-scale and distributed energy resources. Alternatives examined by IRP efforts typically include assessing generating capacity additions (thermal and renewable), implementing energy efficiency (EE) and demand response programs, and determining system transmission and distribution impacts and requirements for plan implementation. Key assumptions and risks that are assessed through scenario or sensitivity analyses typically include fuel prices, load growth, variability of renewable resources, market structure, environmental regulations, and regulatory requirements.

Key steps taken in developing an IRP include:

- forecasting future loads
- identifying potential resource options to meet those future loads
- determining an optimal mix of supply resources based on the goal of minimizing system costs
- receiving and responding to public participation

- determining an optimal resource plan within the framework of key parameters and metrics that reflect the overall objectives of the planning process.

The conditions and circumstances in which utilities must make decisions about how to meet customers' future electric energy needs are ever-changing. Decisions are influenced by the costs and availability of different resource alternatives and by changes in environmental regulations, commodity prices, technology advancements, and economic conditions at large. Economic growth has slowed in recent years, and future demand will continue to grow at a slower pace due in large part to increases in energy efficiency and distributed generation. As a result, the need for new sources of generation is being influenced more by the need to replace existing less efficient and inappropriately-sized generation configurations (relative to system dynamics) and less by the need to serve a growing demand profile.

In developing this IRP, VIWAPA established three key goals in conjunction with the overarching objective for cost minimization:

- Maintaining or improving system reliability and integrity
- Expansion of renewable resources
- Fuel diversity

VIWAPA also sought input into the IRP process by working with advisors of the Public Service Commission (PSC), members of the public, and other key stakeholders.

The preferred plan developed to meet these goals will be fully implemented by 2022 and will include a fleet of highly efficient, reliable, cost effective thermal and renewable generation resources that reflect the following system characteristics:

- Thermal generation facilities that reflect smaller, more modular configurations that are better suited to meet the flexibility requirements of increasing renewable energy penetration and dramatically improve system reliability;
- Dual-and tri-fuel fired facilities that mitigate the risk of single fuel supply interruption and/or price volatility;
- An expansion of renewable energy resources which represent more than half of all installed generation capacity on the islands;
- Significantly lower costs than achieved through the current system configuration.

The remaining sections of this report (Report) present an overview of the preferred plan for each island (Section 1.1), Introduction and key assumption (Section 2), a description of each of the elements in the IRP Process (Section 3), a summary of existing VIWAPA generation technologies (Section 4), Renewable energy technologies and resource potential on the islands (Section 5, Section 6, and Section 7), and discussion on the principles of avoided costs (Section 8).

1.1 PREFERRED PLAN OVERVIEW

The recommended IRP configuration consists of the following for the island of St. Thomas:

- Extend the lease contract for existing Unit 25 for 12 months;
- Lease a GE TM2500+ beginning January 2017 for one year and retire STT 14 in March 2017;
- Lease 3 Wartsila (or similar reciprocating engine technology) 20V34SG units beginning in October 2017;
- Purchase and install 3 Solar Taurus 70 turbines (or similar gas turbine technology) in March 2018;
- Purchase and install 3 Wartsila 20V34SG units beginning October 2018 and retire Unit 23 in June 2019;
- Purchase and install 3 Solar Taurus 70 gas turbines in October 2019;
- Purchase and install 3 Solar Taurus 70 gas turbines in October 2020 and retire Unit 18 in December 2020;
- Renewable supply-side options will consist of existing and planned solar and wind generation.

For the island of St. Croix, the preferred plan includes the following:

- Purchase and install 3 Solar Taurus 70 units in October 2018;
- Retire Unit 19 in December 2018;
- Purchase and install 3 Wartsila 20V34SG units in October 2019;
- Retire Unit 17 in December 2019;
- Purchase and install 2 Solar Taurus 70 units in October 2020;
- Retire Unit 16 in December 2020;
- Purchase and install 1 Solar Taurus 70 unit in October 2022;
- Retire Unit 20 in December 2022;
- Renewable supply-side options will consist of existing and planned solar and wind generation.

The renewable supply-side system configuration for the recommended plan includes the following existing resources:

PROJECT	RESOURCE TYPE	CAPACITY MW (AC)(1)	ESTIMATED ANNUAL ENERGY (MWH/YR)	ESTIMATED CAPACITY FACTOR (%)
USVI Solar I	Solar PV	4.21	10,931(2)	21.5
Toshiba Solar	Solar PV	3.9	8,633(2)	24.6
Port Authority PV - St Thomas	Solar PV	0.45	978(4)	24.7(5)
Net Metering - St Thomas / St. John	Various	10.5	17,011(4)	18.5(5)
Net Metering - St Croix	Various	5.8	15,006(4)	18.3(5)
TOTAL		24.9	52,560	24.1

(1)From Renewables Data Sheet provided by VIWAPA.
(2)Annual Projected MWh from PPA document.
(3)Based on updated input from VIWAPA – project will be providing 8 MW continuous output.
(4)Annual MWh estimated based on estimated Net Capacity Factor.
(5)Estimated through PVsyst energy modeling.

Figure 1-1 Summary of Existing Solar Resources

In addition to the existing renewable energy resources listed above, the recommended plan includes the following resource additions (or an equivalent configuration/project):

PROJECT	RESOURCE TYPE	ESTIMATED CAPACITY MW (AC)	ISLAND	PROJECT STATUS	EXPECTED ONLINE DATE
UVI PV – St. Thomas	Solar PV	1.24	St. Thomas	Contracted construction	Q4 2017
UVI PV – St. Croix	Solar PV	0. 87	St. Croix	Contracted construction	Q4 2017
Port Authority PV – St. Croix	Solar PV	3.0	St. Croix	RFP being drafted	Q4 2018
USVI Solar I – St. Croix Solar LLC	Solar PV	3.0	St. Croix	Contracted construction	Q1 2018
USVI Solar II – St. Croix Solar LLC	Solar PV	3.0	St. Croix	Contracted construction	Q1 2018
Genesis Brew	Solar PV	0.78	St. Croix	QF/PPA Negotiation	Q4 2021
Bovoni Ridge Solar	Solar PV	3.0	St. Thomas	PPA Negotiation	Q4 2021
Bovoni Wind	Wind	10.0	St. Thomas	QF/PPA Negotiation	Q4 2021
Genesis Brew	Wind	0.94	St. Croix	QF/PPA Negotiation	Q4 2021
Waste Management WTE	Landfill Gas	1.2	St. Thomas	Ready to come online	Q4 2021
Dispatchable Biomass	Biomass	8.0	St. Thomas	NA	Q4 2021
TOTAL		35.0			
All data from Renewables Data Sheet provided by VIWAPA.					

Figure 1-2 Summary of New Solar Resources

Once fully installed, the renewable resources will comprise the following aggregate percentage of total system installed capacity:

Name	Area	Maximum Capacity (MW)	Commission Date	Total MW	Accumulated Renewable Capacity % of Peak Demand
St. Croix NEM	St. Croix	5.8	1/1/2014	5.8	5%
Toshiba Solar	St. Croix	3.9	1/1/2014	9.7	8%
Port Authority PV STT	St. Thomas	0.5	1/1/2014	10.2	8%
St Thomas NEM	St. Thomas	10.5	1/1/2014	20.7	16%
USVI Solar I STT	St. Thomas	4.2	1/1/2014	24.9	19%
UnivVI Solar STX	St. Croix	0.9	12/1/2017	25.7	20%
UnivVI Solar STT	St. Thomas	1.2	12/1/2017	27.0	21%
USVI Solar I STX	St. Croix	3.0	3/1/2018	30.0	23%
USVI Solar II STX	St. Croix	3.0	3/1/2018	33.0	26%
Port Authority PV STX	St. Croix	3.0	12/1/2018	36.0	28%
Dispatchable Biomass Resource	St. Croix	8.0	12/1/2021	44.0	34%
Genesis Brew Solar	St. Croix	0.8	12/1/2021	44.7	35%
Genesis Brew Wind	St. Croix	0.9	12/1/2021	45.7	36%
Bovoni Ridge Solar	St. Thomas	3.0	12/1/2021	48.7	38%
Bovoni Wind	St. Thomas	10.0	12/1/2021	58.7	46%
Waste Management WTE	St. Thomas	1.2	12/1/2021	59.9	47%
Additional MW Needed to meet Renewable Requirement (Act 7075)				4.2	50.1%

Figure 1-3 Percent of Future Aggregate Capacity from Renewable Energy

1.2 CONCLUSION

Over the last 18 months, in conjunction with the Public Service Commission advisors, the public, and key stakeholders, VIWAPA has developed and is executing a plan to transition its fossil generation fleet to a cleaner and more fuel diverse portfolio to provide service to customers in a safe, reliable and environmentally responsible manner at a reasonable cost.

The development of the preferred resource plan focused on several key objectives, including improving system reliability, cost minimization, fuel diversity, and renewable energy resource expansion. When fully implemented, the preferred plan will afford VIWAPA customers an economically improved generation fleet that will accommodate future adaptation of increasing levels of renewable resource technology. It will also facilitate flexibility in managing the risks associated with changes in conditions and circumstances that influence resource decisions. In short, our strategy and plan allow VIWAPA to responsibly transition to cleaner, more diverse sources of energy in a way that is beneficial to VIWAPA customers, stakeholders, and the environment.

2 Introduction

Black & Veatch has prepared this Integrated Resource Plan (IRP) Cost Study to evaluate capacity and energy supply options associated with serving the power requirements on the islands of St. Thomas and St. Croix, for the period 2017-2036.

The remainder of this section describes the integrated resource planning process, VIWAPA's electrical system load, generating facilities, and supply side options considered in this study.

2.1 PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

The principal assumptions used for the evaluation are summarized in this section..

Based on discussions with VIWAPA, it has been assumed that demand and energy sales will remain flat through 2036 on the islands of St. Thomas and St. Croix. General inflation is assumed to be 1.5 percent per year. The present worth discount rate assumed is 5.25 percent. The technologies, fuel type, rated capacity, availability, heat rate data, and O&M costs associated with the VIWAPA's existing generating resources used in this IRP are based on information provided by VIWAPA.

The VIWAPA demand forecast, basis for pricing for emissions allowances, and forecasts for liquid fuel prices are presented below.

2.1.1 Electric Demand Summary

The monthly and annual VIWAPA demand forecast used in this IRP Study is shown in Table 2-1. The forecast demand is assumed to remain unchanged for all years of the analysis.

Table 2-1 Monthly Demand and Energy Forecast, 2016

	ST CROIX				ST THOMAS			
	Total Energy, GWh	Peak Demand, MW	Average Demand, MW	Load Factor	Total Energy, GWh	Peak Demand, MW	Average Demand, MW	Load Factor
January	23.303	35.300	31.322	88.7%	34.869	56.440	46.867	83.0%
February	21.234	36.290	30.509	84.1%	30.701	55.430	44.111	79.6%
March	23.628	35.430	31.758	89.6%	33.927	55.150	45.601	82.7%
April	22.731	35.320	31.571	89.4%	32.821	56.810	45.585	80.2%
May	23.620	35.530	31.747	89.4%	33.675	56.170	45.262	80.6%
June	23.901	38.000	33.196	87.4%	33.524	60.600	46.561	76.8%
July	25.035	36.350	33.649	92.6%	37.389	62.000	50.253	81.1%
August	25.077	36.730	33.706	91.8%	36.135	59.490	48.569	81.6%
September	24.434	37.140	33.935	91.4%	35.376	60.090	49.134	81.8%
October	25.574	37.190	34.374	92.4%	36.281	59.680	48.764	81.7%
November	23.247	36.560	32.288	88.3%	34.426	59.580	47.814	80.3%
December	23.717	35.910	31.878	88.8%	34.976	57.270	47.011	82.1%

Annual	285.503	38.000	32.503	85.5%	414.100	62.000	47.143	76.0%

2.1.2 Emissions Allowance Price Projections

VIWAPA provided emission allowance price projections based on emissions rates established by the USVI Department of Planning and Natural Resources (DPNR). The value for emission rates has remained consistent at \$50 per ton for both nitrogen oxides (NO_x) and sulfur dioxide (SO_2) for the past several years. Therefore, the IRP assumed that the rates will remain at \$50/ton in real terms throughout the study period. The US Environmental Protection Agency (EPA) has not published carbon dioxide (CO_2) target rates for the Virgin Islands and therefore the assumed cost for CO_2 emissions is zero.

2.1.3 Projected Delivered Prices

Black & Veatch developed fundamental forecasts for the delivered price of liquefied propane gas (LPG) and Fuel Oil to the islands of St. Croix and St. Thomas. The forecasts developed are summarized in Table 1-2 and depicted in **Error! Reference source not found.**.

Table 2-2 Delivered Fuel Price Forecast (2016$/MMBtu)

YEAR	FUEL OIL	LPG
2016	12.39	9.41
2017	13.26	9.84
2018	14.25	10.35
2019	15.75	11.49
2020	16.84	13.65
2021	17.74	14.01
2022	18.71	14.40
2023	19.25	14.61
2024	19.53	14.72
2025	19.81	14.83
2026	20.09	14.94
2027	20.37	15.05
2028	20.41	15.07
2029	20.69	15.18
2030	20.98	15.30
2031	21.26	15.41
2032	21.55	15.52
2033	21.84	15.64
2034	22.13	15.75
2035	22.17	15.77

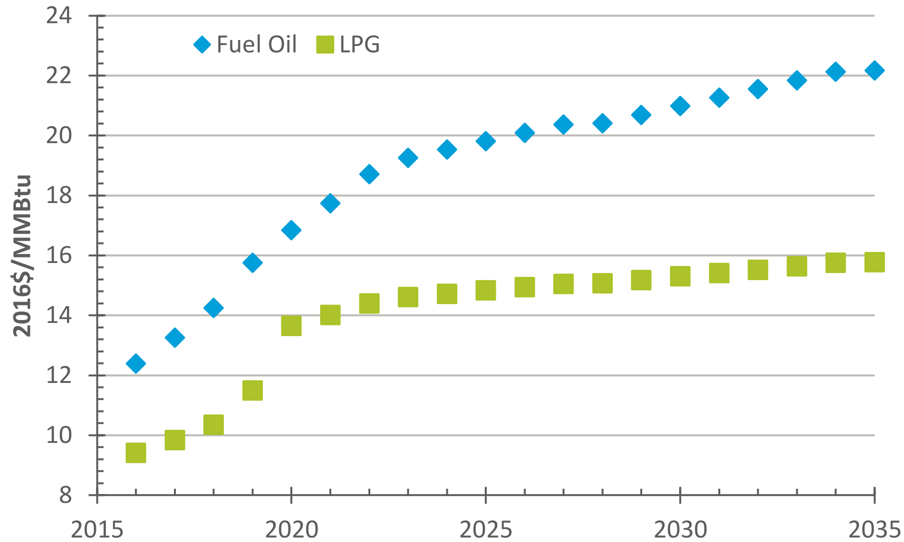


Figure 2-1 Delivered Fuel Price Forecast (2016$/MMBtu)

3 Integrated Resource Planning Process

3.1 DEVELOPING AN IRP

Resource planning is the process that utilities undertake to determine generation resources required to meet future peak and energy demand on its system, while ensuring an adequate reserve margin is maintained for system reliability and integrity, by analyzing a combination of supply and demand considerations over a specified study period. Utilities are frequently required by state legislation or regulation to undertake planning efforts that are then reviewed by state public utilities or service commissions.

Through the evaluation of various supply and demand-side alternatives, the IRP process can be used to develop guidelines for procurement decisions in a manner that satisfies core principles of system reliability, fiscal responsibility, environmental stewardship, and provides a reasonable degree of flexibility to respond to future regulations and technological changes. The best resource plans create a reasonable balance between fiscal responsibility and environmental stewardship, and present reasonable risks and associated costs to customers. All plans selected must maintain generation reliability at or above industry-standard levels.

IRPs are economically developed and evaluated; they utilize economic analyses and methodologies to assess various scenarios and sensitivities to arrive at an *economically* optimal plan. The optimal economic plan may or may not reflect the same conclusions that a pure financial analysis might conclude; one considers the most economically beneficial plan irrespective of a utilities financial condition. Financial factors such as borrowing costs, capital structure, timing of cash flows and earnings, are excluded from this economic evaluation process. Incorporation of financial metrics into the economic results may result in modifications to the structure, timing, and design of the preferred or recommended plan.

IRPs have many benefits to consumers as well as positive impacts on the environment. This is a planning process that produces results that, if correctly implemented, provides the lowest costs at which a utility can deliver reliable energy services to its customers. IRPs differ from traditional resource planning in that it requires the use of sophisticated analytical tools that are capable of fairly evaluating and comparing the costs and benefits of supply and demand resources as well as the integration of utility-scale and distributed energy resources.

Alternatives examined by IRP efforts include assessing generating capacity additions (thermal and renewable), implementing energy efficiency (EE) and demand response programs, and determining the system transmission and distribution impacts and requirements for plan implementation. Uncertainties or risks typically assessed through scenario or sensitivity analyses in IRPs include fuel prices, load growth, variability of renewable resources, market structure, environmental regulations, and regulatory requirements.

Key steps taken in developing an IRP include:

- forecasting future loads
- identifying potential resource options to meet those future loads
- determining an optimal mix of supply resources based on the goal of minimizing system costs

- receiving and responding to public participation
- determining an optimal resource plan within the framework of key parameters and metrics that reflect the overall objectives of the planning process

These key steps in the resource planning process are illustrated in **Error! Reference source not found.**.

STEP 1

ASSESS NEEDS
Develop forecasts of load growth, existing plant condition, contract terms and operational constraints to determine resource needs over the planning period.

STEP 2

CONSIDER RESOURCE SOLUTIONS
Evaluate available generation resources, including conventional, renewable and long term market power purchases to identify the role each will play in meeting customer needs.

STEP 3

EXAMINE PLANNING FRAMEWORK AND RISKS
Identify and assess challenges inherent in the current business and regulatory environment. Develop a multi-faceted risk management approach that considers how plan drivers may change during the Planning Period.

STEP 4

DEVELOP RESOURCE PORTFOLIOS
Develop resource portfolios through screening process, followed by detailed quantitative and qualitative evaluation process for preferred portfolios. Evaluation relies upon needs assessment and planning data specified in previous steps.

STEP 5

PERFORM SCENARIO AND RISK ANALYSIS
Further evaluate preferred resource portfolios through scenario and risk analysis, to assess performance under range of potential market and industry conditions.

STEP 6

IDENTIFY PLAN
Identify "optimal portfolio" and resource plan based on detailed evaluations and scenario analysis. The goal and intent is that any identified resource portfolio(s) will reliably and sustainably serve demand, utilize renewable and energy efficient resources and account for inherent risks at a reasonable long-term cost and be flexible enough to respond to any business, policy or regulatory changes.

Figure 3-1 Integrated Resource Planning Process

This IRP provides an assessment of the future electric energy needs of the US Virgin Island's customers over the next 20 years and the preferred plan for meeting those needs. The plan includes energy efficiency program offerings, retirement of all existing thermal capacity and installation of higher efficiency reciprocating and micro turbine technologies sized more appropriately to provide greater system reliability and fueled by cleaner-burning liquid propane, and expansion of diverse renewable energy resources. Execution of the VIWAPA preferred plan will ensure that VIWAPA customers' long-term electric energy needs are met in a safe, reliable, cost-effective and environmentally responsible manner.

The conditions and circumstances in which utilities must make decisions about how to meet customers' future electric energy needs are ever-changing. Decisions are influenced by the costs and availability of different resource alternatives and by changes in environmental regulations, commodity prices, technology advancements, and economic conditions at large. Economic growth has slowed in recent years, and future demand will continue to grow at a slower pace due in large part to increases in energy efficiency and distributed generation. As a result, the need for new sources of generation is being influenced more by the need to replace existing less efficient and inappropriately-sized generation configurations (relative to system dynamics) and less by the need to serve a growing demand profile.

In developing the IRP, VIWAPA established three key criteria to be achieved in conjunction with the overarching objective for cost minimization:

- Maintaining system reliability and integrity
- Expansion of renewable resources
- Fuel diversity

The flowchart presented in Figure 3-2 illustrates how these considerations and objectives were incorporated into the VIWAPA IRP process. Fundamental activities key to the process included:

- Review of existing resources: both from an economic and operational perspective
- Evaluation of new resource options: there is a universe of potential with both conventional and renewable options evaluated
- Establishing metrics and parameters: for example, regulatory, environmental compliance, etc.
- Determining the optimal mix of resources based on the goals of minimizing future electric system costs, renewable resource targets, and other tangible and intangible objectives
- Receiving and responding to stakeholder participation
- Creating and implementing the resource plan

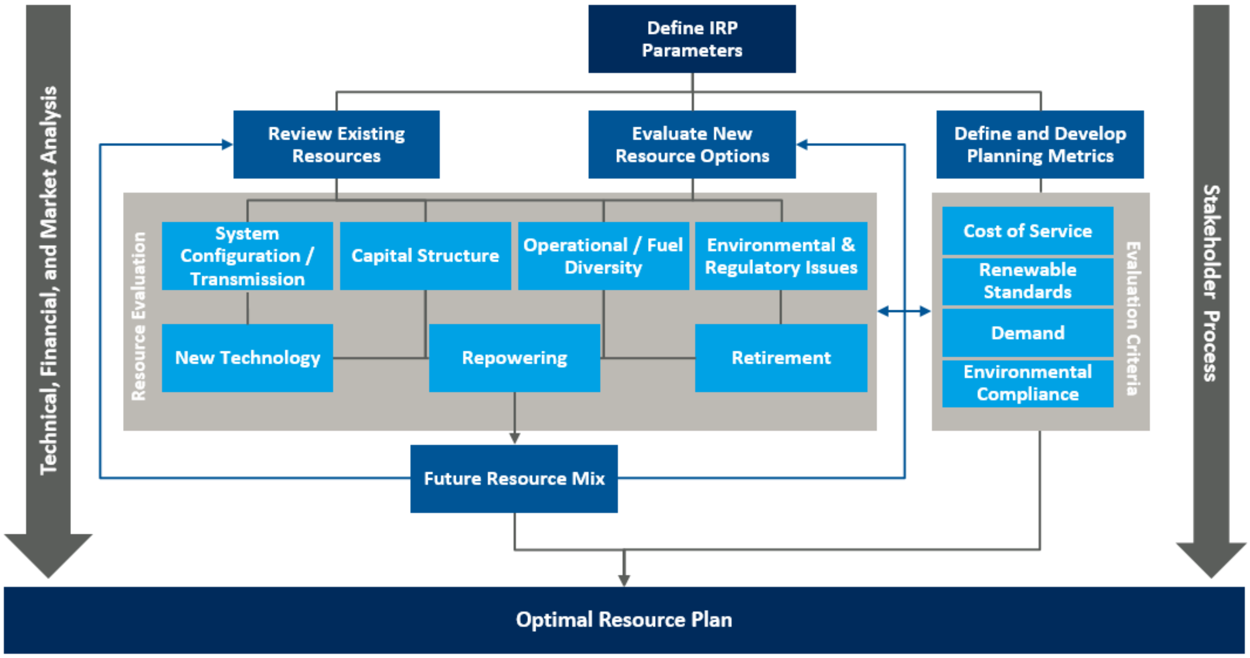


Figure 3-2 IRP Process Flowchart

It is critical to understand that an IRP is *dynamic* in nature, in that it represents a snapshot of a continuous process that should evolve and transform over time. It's intended to provide a methodology and framework for the interminable process of assessing a utilities ever-changing business and operating requirements and adapting them to changing technology, regulations, and customer behavior. Assumptions, scenarios, and results are all challenged and updated as information and events unfold, and the process is continually revisited under formal or informal resource planning efforts.

Technological changes, innovation, and declining costs may prospectively attribute validity and value to outcomes and plans that are currently uneconomic. As such, it is critical to implement resource plans and include options that can be adapted and/or adjusted over time as circumstances dictate. The preferred plan identified in the report provides for a modular design that can be incrementally developed and modified as system and economic conditions evolve.

3.2 THE STAKEHOLDER PROCESS

It is important for an IRP to be developed and written with the aid of a public process. Stakeholder mapping ensures that all relevant stakeholder groups are identified and represented, the material issues are identified and addressed, participants are engaged and involved, feedback is received and considered, the recommended plan is effectively communicated and the implementation plan is clearly understood by all parties involved. These key steps are illustrated in Figure 3-3.

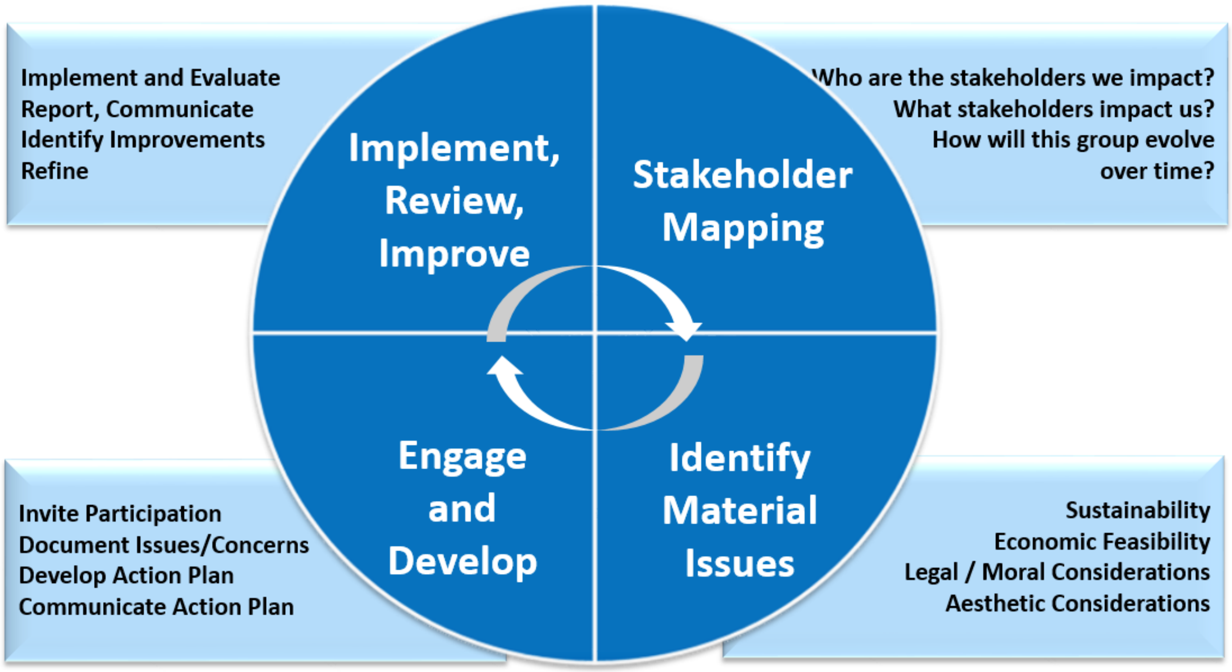


Figure 3-3 Stakeholder Integration Process

One of the key steps in the development of an IRP is the stakeholder process. This step includes identyifyng these groups, conducting meetings, soliciting and receiving feedback, and evaluation of alternatives presented throughout the process.

The overarching objective and goals of the stakeholder process includes:

- Understanding stakeholder concerns and concepts
- Increasing stakeholders' understanding of the IRP process, key assumptions, and challenges
- Providing a forum for productive stakeholder feedback at key points in the IRP process to inform VIWAPA's decision-making
- Complying with Commission rules and objectives

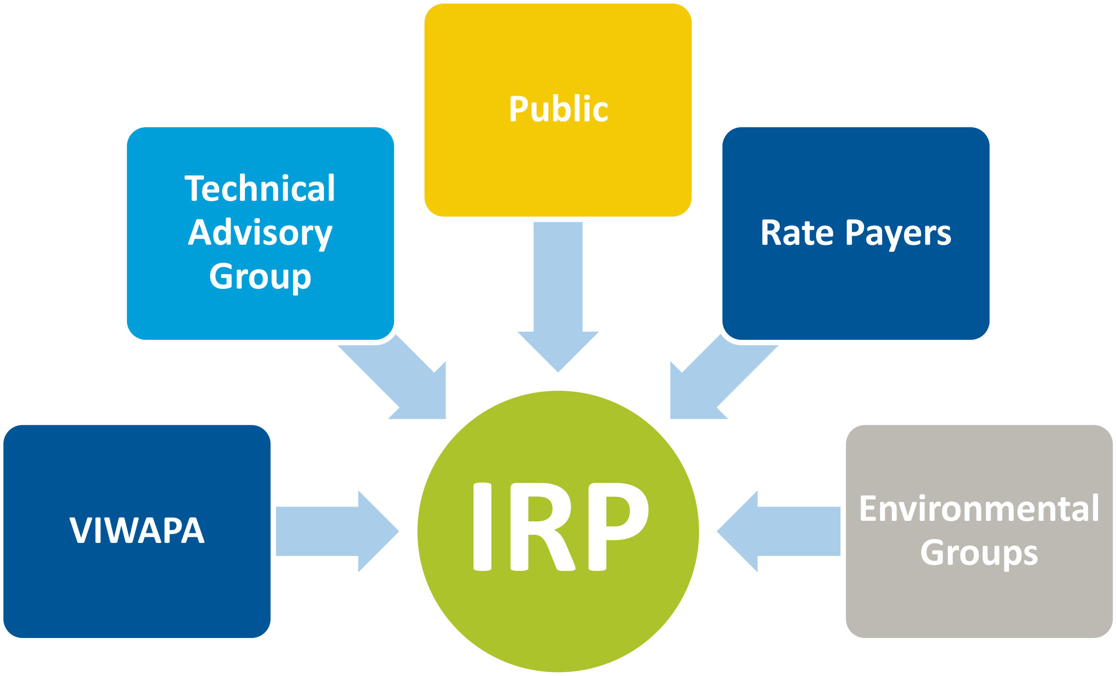


Figure 3-4 Stakeholder Engagement Universe

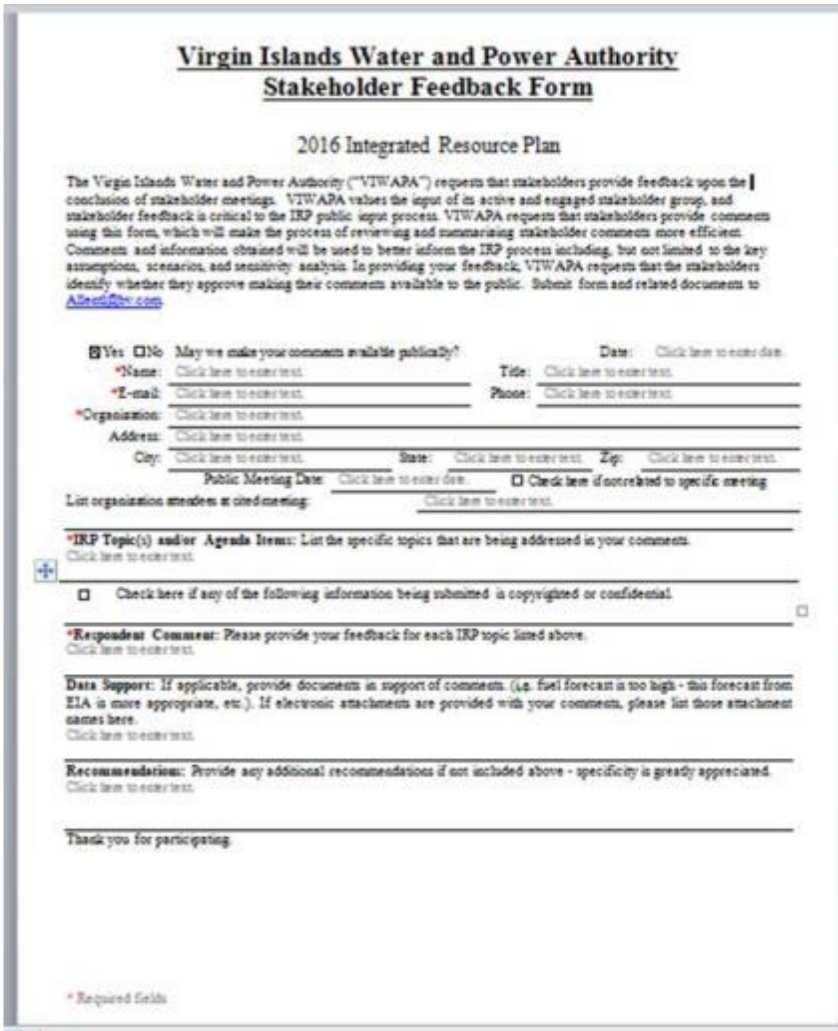
The intent of stakeholder meetings is to solicit input from the stakeholders, address all questions and comments from open season Q&A discussions and commentary, provide feedback from key stakeholder portfolio construct meetings, and faciliate discussions to arrive at a final stakeholder portfolio construct for additional analysis.

Throughout the IRP development process, VIWAPA actively sought input from a variety of stakeholders and constituents. Participants included PSC staff, economic development and commerce groups, customers, developers, environmental organizations, governmental agencies, consultants, the press and other interested parties who joined the planning process as stakeholder participants in three separate meetings held on each island.

The public and stakeholder meetings were held the week of April 20, 2015, the week of May 23, 2016 and the week of October 24, 2016. Meeting venues included multiple sites across St. Thomas, St. Croix and St. John accessible to the public and stakeholder groups. Each meeting covered different aspects of IRP planning activities. At the meetings, members provide contributions to, and assessments of, modeling assumptions, modeling processes, and results of planning scenarios and studies.

WAPA greatly appreciated the valuable contributions made by all stakeholders and thanks each participant who attended and participated at these meetings.

To facilitate this input and interaction, WAPA provided this Stakeholder Feedback Form to all participants. All comments and suggestions were documented, reviewed, and evaluated during the process, resulting in several modifications to the assumptions and process. An example of the VIWAPA feedback form is shown in Figure 3-5.



Virgin Islands Water and Power Authority
Stakeholder Feedback Form

2016 Integrated Resource Plan

The Virgin Islands Water and Power Authority ("VIWAPA") requests that stakeholders provide feedback upon the conclusion of stakeholder meetings. VIWAPA values the input of its active and engaged stakeholder group, and stakeholder feedback is critical to the IRP public input process. VIWAPA requests that stakeholders provide comments using this form, which will make the process of reviewing and summarizing stakeholder comments more efficient. Comments and information obtained will be used to better inform the IRP process including, but not limited to the key assumptions, scenarios, and sensitivity analysis. In providing your feedback, VIWAPA requests that the stakeholders identify whether they approve making their comments available to the public. Submit form and related documents to [illegible]@bv.com.

☒Yes ☐No May we make your comments available publically? Date: Click here to enter date.
*Name: Click here to enter text. Title: Click here to enter text.
*E-mail: Click here to enter text. Phone: Click here to enter text.
*Organization: Click here to enter text.
Address: Click here to enter text.
City: Click here to enter text. State: Click here to enter text. Zip: Click here to enter text.
Public Meeting Date: Click here to enter date. ☐ Check here if not related to specific meeting
List organization attendees at cited meeting: Click here to enter text.

***IRP Topic(s) and/or Agenda Items:** List the specific topics that are being addressed in your comments.
Click here to enter text.

☐ Check here if any of the following information being submitted is copyrighted or confidential.

***Respondent Comment:** Please provide your feedback for each IRP topic listed above.
Click here to enter text.

Data Support: If applicable, provide documents in support of comments. (i.e. fuel forecast is too high - this forecast from EIA is more appropriate, etc.). If electronic attachments are provided with your comments, please list those attachment names here.
Click here to enter text.

Recommendations: Provide any additional recommendations if not included above - specificity is greatly appreciated.
Click here to enter text.

Thank you for participating.

* Required fields

Figure 3-5 VIWAPA Stakeholder Feedback Form

From the IRP and stakeholder processes, a Preferred Portfolio was developed which represents the most reasonable overall value to VIWAPA customers over the planning period. The Preferred Portfolio optimizes generation reliability levels and balances fiscal responsibility with environmental sustainability. The Preferred Portfolio also manages commodity price risk and regulatory risk over the planning horizon. New fossil generation is fueled by cleaner-burning propane. Additionally, the Preferred Portfolio allows VIWAPA to obtain its renewable resources target of thirty percent by 2025.

To help VIWAPA plan to achieve the renewable energy target, a renewable energy analysis was conducted. The renewable energy analysis assessed all existing and planned projects to determine total potential renewables that are *technically* feasible including how much physical space is available for each resource. From the universe of technically feasible potential these options were narrowed to operational and economic feasibile options.

3.3 EXPANSION PLANNING AND PRODUCTION COST CALCULATION METHOD

The supply-side evaluations of generating unit alternatives were performed using Strategist, an expansion plan optimization tool and PROMOD, a chronological production costing model that Black & Veatch licenses from Ventyx. These programs have been benchmarked against other optimization programs and have proven to be effective modeling programs.

PROMOD is a computer-based chronological production costing model developed for use in power supply system planning. PROMOD simulates the hour-by-hour operation of a power supply system over a specified planning period. Required inputs include the operating and performance characteristics of generating units, fuel costs, and the system hourly load profile for each year.

PROMOD summarizes each unit's operating characteristics for every year of the planning horizon. These characteristics include, among others, each unit's annual generation, fuel consumption, fuel cost, average net operating heat rate, the number of hours the unit was on line, the capacity factor, variable operations and maintenance (O&M) costs, and the number of starts and associated costs. Fixed O&M costs were included only for units, where applicable. Fixed O&M costs for existing units are generally considered sunk costs and PROMOD does not consider Fixed O&M in developing the dispatch costs of the units but reports it as part of the operating costs.

Once the optimum expansion plan was developed in Strategist, Black & Veatch used PROMOD, which is an hourly chronological dispatch tool that dispatches the units against load and market prices to determine the system operating costs for all years in the study period. PROMOD simulates hourly operation of the VIWAPA system over the planning horizon and calculates the system fuel and variable operating maintenance costs, plus the incremental capital cost and fixed O&M costs of new unit additions. These incremental system costs are estimated for each year in the planning horizon and are summed on a present value basis to determine the CPWC of the VIWAPA system. Generally, the CPWC of PROMOD is considered to be more accurate than the results obtained in Strategist because Strategist uses a representative load duration curve and does not consider all unit performance information as does PROMOD. In conclusion, the least cost capacity plan is often selected as the best plan, but this is not necessarily always the case. It is possible that the plan with the lowest CPWC cost may not be the best plan if there is sufficient risk in the plan or if the plan is not considered attainable.

4 Existing Generation Facilities

VIWAPA has primary generation facilities on the islands of St. Thomas and St. Croix, and has limited backup generation facilities on the island of St. John. Except for emergency situations, the electric power and energy requirements of the island of St. John are generated on the island of St. Thomas and transmitted to the island of St. John by means of two underwater cables. Because of the extreme water depth between them, the islands of St. Thomas and St. Croix are not interconnected electrically.

This section provides further detail on VIWAPAs existing generation sources.

4.1 EXISTING FOSSIL FUEL GENERATION

VIWAPA's generating facilities on the island of St. Thomas (STT) are located at the Randolph E. Harley Generating Station at Krum Bay, which is on the southwestern end of the island. All electric generation for the islands of St. Thomas and St. John, and the two smaller islands, Hassel Island and Water Island, are located at this site, except for an emergency diesel-generating unit located on the island of St. John. In addition to generation facilities, the Krum Bay site includes water production, fuel oil unloading and storage, transportation, and warehouse facilities. In 1997, VIWAPA installed a heat recovery steam generator ("HRSG"). The HRSG can utilize the exhaust gases from either or both combustion turbine Units No. 15 and No. 18 for the production of steam for electric generation, using the steam turbine Unit No. 11.

All of the existing generation facilities on the island of St. Croix (SC) are located at the Estate Richmond site on the north shore of the island near Christiansted. VIWAPA installed a HRSG on at the Estate Richmond site on St. Croix to convert combustion turbine Units No. 16 and No. 20 from simple-cycle operation to combined-cycle operation. Although some of the generating units have exceeded their normal life expectancy, VIWAPA has refurbished or reconditioned many of its units to extend their useful lives.

Table 4-1 Existing Fossil Generation as Modeled

GENERATOR	RESOURCE TYPE	UNIT TYPES[2]	LOCA-TION[1]	MODELED CAPACITY (MW)	FULL LOAD HEAT RATE (MMBTU /MWH)
STX 16 11	CC	GE MS5001P CT GE STG	STX	22.97	11.600
STX 20 11	CC	GE MS5001PA CT GE STG	STX	22.97	11.600
STX 17 10	CC	GE MS5001P CT Worthington STG	STX	28.00	11.700
STX 19	CT	GE MS5001PA CT	STX	19.29	16.429
STX Total				**93.23**	
STT 15 11	CC	GE STG GE MS5001P CT	STT	31.00	10.797

GENERATOR	RESOURCE TYPE	UNIT TYPES[2]	LOCATION[1]	MODELED CAPACITY (MW)	FULL LOAD HEAT RATE (MMBTU /MWH)
STT 18 11	CC	GE STG GE PG5371PA CT	STT	31.80	10.607
STT 14	CT	GE MS5001LA CT	STT	15.10	17.484
STT 23	CT	GE P6581B CT	STT	39.20	12.024
STT 25	CT	GE TM2500 CT	STT	21.80	10.500
St. John Diesel	IC	Westinghouse Diesel GenSet	STJ	2.50	20.00
STT Total				**141.4**	
Total				**234.63**	

[1]STT = St. Thomas
[1]STX = St. Croix
[2]GE = General Electric

The generating systems on the islands of St. Thomas and St. Croix involve multi-unit configurations operating in combined cycle operation and single units operating in simple cycle operation. The configurations used in the production cost models for this IRP analysis were identified in consultation with VIWAPA personnel and are as shown in Table 4-1. On the island of St. Thomas, the analysis models combustion turbine Unit No. 15 and/or Unit No. 18 supplying waste heat to the HRSG to supply steam to steam turbine generator Unit No. 11. Unit No. 14, Unit No. 23 and Unit No. 25 operate in simple cycle mode. The configuration described represents the most efficient mode for the system to meet load requirements.

The assumed configuration on the island of St. Croix is that combustion turbine Unit No. 16 and Unit No. 20 supply waste heat to the HRSG to supply steam to Unit No. 11. Unit 17 supplies waste heat to the HRSG to generate steam to drive the steam turbines Unit No. 10. Unit No. 19 will produce electricity in simple cycle mode.

The St. Thomas and St. Croix generators have all been burning fuel oil until recently when VIWAPA began converting the units to burn Liquid Propane Gas (LPG). Projected LPG conversion dates are shown in Table 4-2. The analysis uses the LPG conversion dates provided. VIWAPA indicated that the planned retirement date for St. Thomas Unit 14 is around December 31, 2019.

Table 4-2 Generator LPG Conversion Dates

COMBUSTION TURBINE UNIT	LPG COMMERCIAL OPERATION DATE
STX 16	Completed
STX 17	Completed
STX 19	Completed
STT 15	Completed
STT 14	Not Planned
STT 18	Completed
STT 23	July 2017
STT 25	Not Scheduled

4.2 EXISTING AND PLANNED RENEWABLE ENERGY GENERATION

VIWAPA provided data on the existing renewable energy generation on their system and planned renewable energy generation that is expected to be online in the next few years. VIWAPA provided PPA contract documents, net metering records, and renewable project data sheets. The existing and planned renewable energy generation sources are shown below in Table 4-3.

Table 4-3 Existing and Planned Renewable Energy Generation

PROJECT	RESOURCE TYPE	CAPACITY (MW (AC))	ESTIMATED ANNUAL ENERGY (MWH/YR)	ESTIMATED CAPACITY FACTOR (%)	EXPECTED ONLINE DATE
USVI Solar I – St. Thomas	Solar PV	4.21	7,900	21.4%	Online
UVI PV – St. Thomas	Solar PV	1.20	2,682	25.5%	4th Qtr. 2017
Port Authority PV – St. Thomas	Solar PV	0.45	973	24.7%	Online
Net Metering – St. Thomas	Various	10.5	17,016	18.5%	Online
Waste to Energy – St. Thomas	Methane	1.2	10,512	98.0%	4th Qtr. 2021
Bovoni Ridge Solar – St. Thomas	Solar PV	3.0	6,484	24.7%	4th Qtr. 2021
Bovoni Wind – St. Thomas	Wind	10.0	30,064	34.3%	4th Qtr. 2021
St. Thomas Total		**30.6**	**75,631**	**28.2%**	
Toshiba Solar – St. Croix	Solar PV	3.9	8,516	24.9%	Online
UVI PV – St. Croix	Solar PV	0.87	1,895	24.9%	4th Qtr. 2017
Port Authority PV – St. Croix	Solar PV	3.0	6,566	25.0%	4th Qtr. 2018
Net Metering - St Croix	Various	5.8	11,851	23.3%	Online
Dispatchable Biomass – St. Croix	Biomass	8.0	70,080	98.0%	4th Qtr. 2021
USVI Solar I – St. Croix	Solar PV	3.0	7,208	27.4%	1st Qtr. 2018

PROJECT	RESOURCE TYPE	CAPACITY (MW (AC))	ESTIMATED ANNUAL ENERGY (MWH/YR)	ESTIMATED CAPACITY FACTOR (%)	EXPECTED ONLINE DATE
USVI Solar II – St. Croix	Solar PV	3.0	7,208	27.4%	1st Qtr. 2018
Genesis Brew – St. Croix	Wind	0.94	1,924	23.3%	4th Qtr. 2021
Genesis Brew – St. Croix	Solar PV	0.78	1,702	24.9%	4th Qtr. 2021
St. Croix Total		**29.3**	**116,950**	**45.6%**	
TOTAL		**59.9**	**192,581**	**36.7%**	

5 Renewable Energy Assessment

Black & Veatch conducted an analysis of renewable energy technologies and potential application within the VIWAPA service territory. The assessment included several steps, as described in the following sections, including (1) preparing a summary of existing and planned renewable energy projects, (2) preparing cost estimates for different renewable energy technologies, (3) identifying the potential for additional generation from renewables, and (4) estimating potential annual energy production from wind and solar resources.

The analysis of additional potential generation focused on wind and solar resources. Other renewable technologies include waste-to-energy, landfill gas, biomass, offshore wind, and ocean thermal. As these technologies are typically less cost effective, they were reviewed at a higher level and are discussed in Appendix B.

Based on 2013 and 2014 load data provided by VIWAPA, the annual electricity demand for both St. Thomas and St. Croix is approximately 741,800 MWh/yr, and the peak load is approximately 112 MW. In 2009, USVI passed Act 7075, which established goals for the contribution of renewable energy generation. The goals are defined in terms of "peak demand generating capacity":

- 20 percent by January 1, 2015.
- 25 percent by January 1, 2020.
- 30 percent by January 1, 2025.
- Increasing "until a majority of energy is derived from renewables" (51 percent).

5.1 USVI HAS ALSO SIGNED A MEMORANDUM OF UNDERSTANDING WITH THE U.S. DOE ESTABLISHING A GOAL OF 60 PERCENT OF USVI ENERGY NEEDS FROM RENEWABLE SOURCES. IT IS NOT SPECIFIED WHETHER THIS GOAL IS IN TERMS OF ENERGY SALES (MWH), OR PEAK DEMAND CAPACITY (MW). PLANNED AND EXISTING GENERATION

VIWAPA provided data for existing renewable energy technologies in the form of PPA contract documents, net metering records, and a renewable project data sheet. The existing renewable energy generation sources are summarized in Table 5-1.

Table 5-1 Existing Renewable Energy Generation

PROJECT	RESOURCE TYPE	CAPACITY MW (AC)[(1)]	ESTIMATED ANNUAL ENERGY (MWH/YR)	ESTIMATED CAPACITY FACTOR (%)
USVI Solar I	Solar PV	4.21	7,897[(2)]	21.5
Toshiba Solar	Solar PV	4.00	8,633[(2)]	24.6
Port Authority PV - St Thomas	Solar PV	0.45	978[(4)]	24.7[(5)]
Net Metering - St Thomas / St. John	Various	6.86	17,011[(4)]	18.5[(5)]
Net Metering - St Croix	Various	5.8	15,006[(4)]	18.3[(5)]
TOTAL		**27.71**	**52,560**	**24.1**

[(1)] From Renewables Data Sheet provided by VIWAPA.
[(2)] Annual Projected MWh from PPA document.
[(3)] Based on updated input from VIWAPA – project will be providing 8 MW continuous output.
[(4)] Annual MWh estimated based on estimated Net Capacity Factor.
[(5)] Estimated through PVsyst energy modeling.

The total nameplate capacity of the existing renewable energy projects represents approximately 27.7 MW, or 24 percent of current peak demand. VIWAPA also provided detail of planned projects at various phases of development, shown below in Table 5-2, totaling approximately 26.5 MW.

The combined nameplate capacity for the existing and planned projects represents approximately 54 MW, or approximately 48 percent of the current peak demand. The net metered system totals have continued to increase towards their combined capped total of 15 MW, which when reached will result in approximately 52 percent of the current peak demand from renewables.

Table 5-2 Planned Renewable Energy Generation

PROJECT	RESOURCE TYPE	ESTIMATED CAPACITY MW (AC)	ISLAND	PROJECT STATUS	EXPECTED ONLINE DATE
UVI PV – St. Thomas	Solar PV	1.24	St. Thomas	Contracted construction	Q4 2017
UVI PV – St. Croix	Solar PV	0.87	St. Croix	Contracted construction	Q4 2017

Port Authority PV – St. Croix	Solar PV	3.0	St. Croix	RFP being drafted	Q4 2018
USVI Solar I – St. Croix Solar LLC	Solar PV	3.0	St. Croix	Contracted construction	Q1 2018
USVI Solar II – St. Croix Solar LLC	Solar PV	3.0	St. Croix	Contracted construction	Q1 2018
Genesis Brew	Solar PV	0.78	St. Croix	QF/PPA Negotiation	Q4 2021
Bovoni Ridge Solar	Solar PV	3.0	St. Thomas	PPA Negotiation	Q4 2021
Potential Wind – Bovoni	Wind	10.0	St. Thomas	QF/PPA Negotiation	Q4 2021
Genesis Brew	Wind	0.94	St. Croix	QF/PPA Negotiation	Q4 2021
Waste Management WTE	Landfill Gas	1.2	St. Thomas	Ready to come online	Q4 2021
Dispatchable Biomass	Biomass	8.0	St. Thomas	NA	Q4 2021
TOTAL		**35.0**			

All data from Impact Study Renewables Data Sheet provided by VIWAPA.

The renewable supply-side schedule for existing and planned renewable generation contained in the recommended plan meets or exceeds USVI Act 7075 passed in 2009. The Act established goals for the contribution of renewable energy generation defined in terms of "peak demand generating capacity". Once installed, these renewable resources will comprise the following aggregate percentage of total system installed capacity:

- 20 percent by January 1, 2015.
- 25 percent by January 1, 2020.
- 30 percent by January 1, 2025.
- Increasing "until a majority of energy is derived from renewables" (51 percent).

Table 5-3 Renewable Energy Generation build-out schedule

PROJECT	AREA	CAPACITY MW (AC)	COMMISSION DATE	TOTAL, MW	ACT 7071 GOAL, %	TOTAL, %(1)
St. Croix NEM	St. Croix	5.8	1/1/2014	5.8	20	4.5
Toshiba Solar	St. Croix	3.9	1/1/2014	9.7	20	7.6
Port Authority PV STT	St. Thomas	0.5	1/1/2014	10.2	20	7.9
St Thomas NEM	St. Thomas	10.5	1/1/2014	20.7	20	16.1
USVI Solar I STT	St. Thomas	4.2	1/1/2014	24.9	20	19.4
UnivVI Solar STX	St. Croix	0.9	12/1/2017	25.7	20	20.1
UnivVI Solar STT	St. Thomas	1.2	12/1/2017	27.0	20	21.1

USVI Solar I STX	St. Croix	3.0	3/1/2018	30.0	20	23.4
USVI Solar II STX	St. Croix	3.0	3/1/2018	33.0	20	25.8
Port Authority PV STX	St. Croix	3.0	12/1/2018	36.0	20	28.1
Dispatchable Biomass Resource	St. Croix	8.0	12/1/2021	44.0	25	34.3
Genesis Brew Solar	St. Croix	0.8	12/1/2021	44.7	25	35.0
Genesis Brew Wind	St. Croix	0.9	12/1/2021	45.7	25	35.7
Bovoni Ridge Solar	St. Thomas	3.0	12/1/2021	48.7	25	38.0
Bovoni Wind	St. Thomas	10.0	12/1/2021	58.7	25	45.9
Waste Management WTE	St. Thomas	1.2	12/1/2021	59.9	25	46.8
Additional Capacity to meet Act 7075		4.2	N/A	64.1	50+	50.1

(1) Total renewable energy calculated as the sum of the peak outputs of the projects commissioned divided by the sum of the forecast peak demands at St. Croix, St. Thomas, and St. John (Total MW divided by 128).

5.2 TECHNICAL POTENTIAL ANALYSIS

Black & Veatch analyzed the gross technical potential for the development of distributed solar photovoltaic (PV) (rooftop mounted systems), utility scale PV (large, ground mounted systems), and utility scale wind projects on USVI using various geospatial techniques. The sections below summarize the approach, assumptions, and results of that analysis.

For all resources analyzed, the results represent a maximum physical resource potential ("technical potential"). This potential is estimated by identifying the land area (or rooftop area) feasible for project development, using criteria discussed in the following sections.

The following considerations were excluded from this analysis:

- Grid Integration (feeder loading, interconnection, etc.).
- Load-limited capacities of net-metered systems.
- Site access, transport, and construction logistics.
- Environmental review (birds, endangered species, etc.).
- Geotechnical review.
- Visual impacts.
- Hurricane risk.
- Microwave beam path interference.
- Land use and zoning data (which would allow for the distinction of multi-family and single-family residential, commercial, and industrial rooftops as well as agricultural, and other land use designations)

Estimates of energy output from wind and solar resources in USVI, were developed from generic design assumptions and best available resource data to produce a high-level assessment of the generation potential from renewables in USVI.

5.2.1 Distributed (Rooftop) Solar PV

Technical potential for distributed solar PV was estimated using automated processing and analysis of high-resolution aerial photo imagery of USVI, to identify rooftop areas suitable for PV installation. Figure 5-1 shows an example of this processing for an area on St. Thomas.

Figure 5-1 Rooftop PV Imagery Analysis

Once rooftop areas were defined, Black & Veatch applied standard assumptions to translate maximum available rooftop area to reasonable achievable capacity targets, based on industry experience analyzing distributed solar technologies. The assumptions applied are shown in Table A-1 of Appendix A.

The imagery analysis identified over 39,000 individual rooftops in USVI. Use of a 400 ft^2 threshold screening criteria effectively removed approximately 2,600 of those buildings. Table 5-4 summarizes the number of rooftops analyzed on each island.

Table 5-4 Total Rooftops Analyzed

ISLAND	ALL ROOFTOPS	ABOVE 400 SQ. FT. THRESHOLD
St. Thomas	15,319	14,276
St. John	3,394	3,107
St. Croix	20,330	19,073
TOTAL	39,043	36,456

VIWAPA has limits on individual system capacities under the feed-in-tariff (FIT) and net energy metering (NEM) programs, shown below in Table 5-5. Additionally, VIWAPA has limits set on the aggregate PV system capacity under the NEM program: 10 MW on St. Thomas/St. John, and 5 MW on St. Croix.

Table 5-5 VIWAPA Net Metering and Feed-in-Tariff Capacity Limits

PROGRAM	CUSTOMER TYPE	CAPACITY LIMIT (KW AC)[1]
Net Energy Metering	All	10
Feed-in Tariff	Residential	20
Feed-in Tariff	Commercial	100
Feed-in Tariff	Public	500

[1]Capacity not specified as AC or DC rating, Black & Veatch has assumed AC.

Converting each rooftop area to kW capacity using the assumptions in Table A-1, the total gross potential is calculated to be approximately 200 MW. Without parcel zoning data, Black & Veatch was not able to assign a customer type to individual rooftops or cap system sizes accordingly. Table 5-6 presents the results of the rooftop solar PV potential analysis, under various capacity limits applied to all rooftops.

Table 5-6 Total Rooftop PV Gross Potential for Various Capacity Limits (MWac)

ISLAND	SYSTEM CAPACITY LIMIT (KW AC) AND RESULTING POTENTIAL (MW AC)			
	<500 kW	<100 kW	<20 kW	<10 kW
St. Thomas	81	77	65	51
St. John	13	13	13	11
St. Croix	109	101	84	65
TOTAL	**203**	**191**	**162**	**127**

The results in Table 5-6 represent an upper bound on the technical potential for rooftop PV in USVI. As previously mentioned, this does not consider potential challenges associated with grid integration, or the sizing of systems to meet customers load in the case of net metering.

Black & Veatch performed energy modeling to estimate energy output of the identified rooftop PV potential. The methodology and assumptions for this modeling are presented in Appendix A. Table 5-7 presents the results of the rooftop energy modeling analysis, for a representative 5 kW (ac) system.

Table 5-7 Rooftop Solar PV Energy Modeling Results

	LONG TERM GHI (KWH/M^2/YR)	CAPACITY FACTOR (DC)	CAPACITY FACTOR (AC)	ESTIMATED ANNUAL KWH (5 KW AC SYSTEM)
St. Thomas	1894	16.9%	18.5%	8,112
St. John	1888	16.9%	18.5%	8,085
St. Croix	1864	16.7%	18.3%	7,998

As discussed in Appendix B, the resource data used in this assessment predicts the solar resource to be within approximately 1.5 percent for the three islands – however this is well within the margin of uncertainty for this data source. Practically speaking, the solar resource and resulting energy output can be considered to be approximately equivalent throughout the USVI.

5.2.2 Utility-Scale Solar PV

To estimate the technical potential for utility-scale solar PV installations, Black & Veatch performed a Geographic Information Systems (GIS)-based analysis to determine locations in USVI suitable for PV. Using publically available spatial data sets and data provided by VIWAPA, exclusion areas were developed based on the following criteria:

- Excluded Areas:
  - Roads.
  - Wetlands, forests, urban areas, flood areas, and protected areas.
  - Buildings.
  - Airports.
  - Existing and planned renewable energy projects.
  - Irregular resulting shapes inappropriate for development.
- Remaining areas assessed:
  - "Simple" terrain: less than 5 percent slope.
  - "Complex" terrain: between 5 and 20 percent slope.

Typically, Black & Veatch would limit solar PV technical potential to areas with less than 5 percent slope. However, as evidenced in the existing USVI Solar I project site on St. Thomas (shown in Figure 5-2), solar PV installations on USVI may be feasible in more complex terrain, though projects in sited on complex terrain may result in higher total installed costs. Additionally, as shown in Table A-3 of Appendix A, projects in complex terrain are anticipated to require up to 60 percent more land area than an equivalently rated project in simple terrain. Finally, as can be seen in Figure 5-2, complex terrain may dictate a project design that yields sub-optimal orientations, string arrangements, and additional shading, resulting in less efficient energy capture and overall lower capacity factor versus simple terrain.

Figure 5-2 USVI Solar I Project Site (Complex Terrain)

Black & Veatch performed additional manual review and editing of the resulting areas to exclude inappropriate locations, including areas that appear to be residential or commercial, or irregularly shaped parcels that would not be feasible for project development. Figure 5-3 and Figure 5-4 show the resulting areas which meet the exclusion criteria at a 5 percent (orange shapes shown in Figure 5-3) and 20 percent slope limit (yellow shapes shown in Figure 5-4), after the manual editing was performed.

Figure 5-3 Utility Scale Solar Feasibility Areas: Simple Terrain (Less Than 5% Slope)

Figure 5-4 Utility Scale Solar Feasibility Areas: Complex Terrain (Less than 20% Slope)

Without land use and zoning data, the identified areas may include locations which would not be developable. Black & Veatch used an estimate of 10 percent of the gross potential to represent the developable potential.

To convert the resulting acreage to PV system capacity, Black & Veatch has made general PV system design assumptions, summarized in Table A-3 of Appendix A. Table 5-8, Table 5-9, and Table 5-10 show the results of the utility-scale solar PV potential analysis, including total acreage identified, gross MW, and developable MW (i.e., 10 percent of the gross MW).

Table 5-8 Utility-Scale Solar PV Technical Potential: Simple Terrain Sites

SLOPE: LESS THAN 5%	ACRES	GROSS POTENTIAL (MW AC)	DEVELOPABLE POTENTIAL (MW AC)
St. Thomas	0	0	0
St. John	0	0	0
St. Croix	2,793	559	56
Total	**2,793**	**559**	**56**

Table 5-9 Utility-Scale Solar PV Technical Potential: Complex Terrain Sites

SLOPE: BETWEEN 5% AND 20%	ACRES	GROSS POTENTIAL (MW AC)	DEVELOPABLE POTENTIAL (MW AC)
St. Thomas	65	8	0
St. John	6	1	0
St. Croix	7,070	884	88
Total	**7,140**	**893**	**88**

Table 5-10 Utility-Scale Solar PV Technical Potential: All Identified Sites

SLOPE: LESS THAN 20%	ACRES	GROSS POTENTIAL (MW AC)	DEVELOPABLE POTENTIAL (MW AC)
All Islands	9,934	1451	145

Considering only simple terrain sites, the total identified developable potential is approximately 56 MW. Expanding the criteria to include more complex terrain yields an additional 88 MW, for a total of 145 MW for combined simple and complex sites. All of the identified developable potential exists on St. Croix. It is noted that these results are extremely sensitive to the 10 percent estimate used to estimate developable areas.

Black & Veatch modeled energy output for utility-scale solar projects on USVI using assumptions and methodologies outlined in Appendix A. The results of that modeling are shown below in Table 5-11, for a representative 5 MW (ac) system.

Table 5-11 Utility-Scale Solar PV Energy Modeling Results

	LONG TERM GHI	CAPACITY FACTOR (1)	CAPACITY FACTOR (1)	ESTIMATED ANNUAL MWH (1)

	(KWH/M2/YR)	(DC)	(AC)	(5 MW AC SYSTEM)
St. Thomas	1894	18.3%	24.7%	10,797
St. John	1888	18.2%	24.6%	10,775
St. Croix	1864	18.0%	24.3%	10,643

(1)Capacity factors and estimated annual MWh represent a project in simple terrain (<5% slope). Complex terrain sites may exhibit lower capacity factors due to sub-optimal design.

The resulting capacity factors of approximately 24.5 percent (ac basis) imply feasibility for utility-scale solar PV, from a resource perspective. As with the rooftop PV modeling results, the estimated capacity factors and energy output are very similar among the three islands, and within the margin of uncertainty of the solar resource data.

Note the capacity factors and estimated annual energy values represent a project in simple terrain. As mentioned previously in this section, projects in complex terrain may have lower energy yields due to sub-optimal system design. Using the existing USVI Solar I and Toshiba Solar projects as an example, complex terrain sites may yield 10 to 15 percent lower capacity factors than those in simple terrain.

The St. Croix Solar LLC projects, which are to be installed in 2016, are currently planned as single-axis-tracking (SAT) systems. Black & Veatch estimates approximately 15 percent greater energy output for a SAT system versus fixed tilt in USVI. This additional output is at the expense of greater equipment costs. Based on high-level analysis, SAT systems may still provide better project economics in USVI. However, as also presented in this section, there is very limited area, all of which is on St. Croix, which would be flat enough for a large SAT system.

5.2.3 Utility Scale Wind

In general, opportunity for wind development in USVI is uncertain, and may prove to be prohibitively challenging. There are limited areas suitable for development, some of which are located in complex terrain with challenging or no existing access. Even in more moderate terrain, it may be the case that turbine delivery and transport logistics preclude development. However, several successful Caribbean wind projects have recently been developed, and others have been proposed in USVI.

The National Renewable Energy Laboratory (NREL) has conducted extensive analysis of wind energy opportunities in USVI. Black & Veatch incorporated NREL's research into our analysis. In their reports[1,2], NREL identified the Bovoni Landfill area as promising for wind energy development, and conducted a thorough wind resource assessment and energy modeling of that site. Those results included the caveat of challenging transport and construction logistics.

[1] "Wind Power Opportunities in St. Thomas, USVI: A Site-Specific Evaluation and Analysis", National Renewable Energy Laboratory, September 2012

[2] "U.S. Virgin Islands Wind Resources Update 2014", National Renewable Energy Laboratory, December 2014

Currently, several developers are reportedly submitting plans to VIWAPA for a wind energy project at the Bovoni site. The outcome of any development efforts at this site should provide an indication for the potential for utility-scale wind energy development in other parts of USVI.

Black & Veatch performed a GIS-based analysis to identify areas suitable for wind energy development. Similar to the utility-scale solar PV assessment, exclusion areas were developed using data available publicly and provided by VIWAPA. These areas were based on the following criteria:

- **Excluded Areas:**
  - Slopes >= 15 percent.
  - Roads (plus setback for maximum blade height).
  - Wetlands, forests, urban areas, flood areas, and protected areas (urban areas include additional setback for maximum blade height).
  - Buildings (plus 1500 ft. setback).
  - Airports and surrounding areas.
  - Existing and planned renewable energy projects.
  - Irregular resulting shapes inappropriate for development.

The resulting areas were further edited through manual review to exclude areas that were clearly inappropriate for project development, in lieu of detailed land use and zoning data.

Based on the resulting land area, Black & Veatch identified three areas most likely suitable for utility-scale wind energy development, all located on the St. Croix:

- Site #1: The East end of St. Croix.
- Site #2: East of Refinery area.
- Site #3: Northwest ridges of St. Croix.

The approximate locations of these sites are shown below in Figure 5-5.

Figure 5-5 Utility-Scale Wind Development Areas (Source: Google Earth)

To estimate the potential capacities at each site, Black & Veatch produced preliminary layouts assuming a minimum turbine separation and orientation. Black & Veatch modeled the Vestas V100 1.8 MW wind turbine as representative of large-scale, and the Vergnet GEV MP C 275 kW turbine as representative of a smaller turbine type which may be more suitable for some locations where height restrictions, setbacks, or extreme weather preclude larger turbines. Both of these turbine types offer packages for installation in hurricane-prone regions. The characteristics of each turbine type are shown in Table A-5 of Appendix A. Further detail of the layout development is provided in Appendix A.

The resulting estimated capacities for each site are shown in Table 5-12 and Table 5-13, for both turbine types. Note that these potentials represent only one or the other turbine type, not the combination of both turbine types.

Table 5-12 Utility-Scale Wind Potential: Vestas V100

VESTAS V100	TURBINE COUNT	TOTAL CAPACITY (MW AC)
Site #1: East End of St. Croix	7	12.6
Site #2: East of Refinery	10	18
Site #3: NW Ridges of St. Croix	5	9
Total	**22**	**39.6**

Table 5-13 Utility-Scale Wind Potential: Vergnet 275

VERGNET GEV MP C	TURBINE COUNT	TOTAL CAPACITY (MW AC)
Site #1: East End of St. Croix	16	4.4
Site #2: East of Refinery	19	5.3
Site #3: NW Ridges of St. Croix	5	1.4
Total	**40**	**11.0**

Using the Vestas V100 as a representative utility-scale wind turbine, the total potential capacity at all three sites combined is approximately 40 MW. This is considered a reasonable and representative estimate – however there are many different available turbine types which may be suitable for these sites, some with larger generators which may provide additional project capacity.

As is also noted by NREL in their analysis[2], the site east of the refinery on St. Croix likely offers the most opportunity for project development, due to its relatively moderate terrain, site access, and (as reported by NREL) positive feedback from local stakeholders. Black & Veatch has estimated the potential for 10 Vestas V100 turbines to be located in this area, for a capacity of 18 MW.

As would be expected, more Vergnet turbines can fit within the identified buildable areas, though still at a significantly lower total capacity than the Vestas. However, the Vestas turbine, with its larger generator, larger rotor, and taller hub height, will produce considerably higher energy output than a Vergnet turbine at the same location.

To estimate wind energy output for the identified project areas, Black & Veatch utilized previous analyses conducted by NREL, USVI, and AWS Truepower. Those analyses summarized meteorological data collected on St. Thomas (Bovoni) and St. Croix (Longford), which was also compared to wind mapping exercise performed by AWS Truepower. The results of those analyses are summarized in NREL's reports[1,2], and the wind flow modeling results are provided as GIS shapefiles through NREL's Wind Prospector website.

Appendix A provides additional detail on the wind energy modeling assumptions and methodology used in this analysis. The resulting energy estimates are shown in Table 5-14 and Table 5-15.

The Vestas turbine produces very feasible NCF values at all of the potential locations. While Site #2 ("East of Refinery") does show a lower NCF than Site #1, an average NCF of 41 percent is still considered to be a promising resource for project development. Given the potential larger capacity at this site and less challenging project logistics, these results further illustrate the relative promise of this particular location.

Table 5-14 Utility-Scale Wind Energy Estimates: Vestas V100 1.8 MW Turbine

VESTAS V100	TURBINE COUNT	TOTAL CAPACITY (MW AC)	NCF RANGE	AVERAGE NCF	ESTIMATED ANNUAL MWH
Site #1: East End of St. Croix	7	12.6	42% - 49%	46%	50,221
Site #2: East of Refinery	10	18.0	37% - 48%	41%	64,333
Site #3: NW Ridges of St. Croix	5	9.0	40% - 44%	41%	32,482
Total	**22**	**39.6**	**37% - 49%**	**42%**	**147,037**

Table 5-15 Utility-Scale Wind Energy Estimates: Vergnet 275 kW Turbine

VERGNET GEV MP C	TURBINE COUNT	TOTAL CAPACITY (MW AC)	NCF RANGE	AVERAGE NCF	ESTIMATED ANNUAL MWH
Site #1: East End of St. Croix	16	4.4	24% - 34%	29%	11,178
Site #2: East of Refinery	19	5.2	19% - 25%	22%	10,070
Site #3: NW Ridges of St. Croix	5	1.4	18% - 24%	21%	2,541
Total	**40**	**11**	**18% - 34%**	**25%**	**23,789**

As expected, the Vergnet turbine produces a significantly lower NCF than the Vestas V100 for a given location, due to its lower hub height and smaller rotor. This type of turbine is most feasible as an option for USVI locations where land use, setbacks, or heights are restricted, or visual impact is to be minimized. Additionally, a smaller turbine may offer transport and construction advantages where site access and terrain preclude large turbines.

The ranges in NCF for each site reflect the complexity of the terrain and resulting varying resource. Considering as well the uncertainty in the wind flow model, it is further recommended that thorough wind resource assessments are conducted prior to project development to confirm the wind speeds throughout a specific site. As mentioned previously in this section, turbine layouts modeled here do not consider several aspects that would be necessary to review and confirm the feasibility of each turbine location. These results do however provide a reasonable estimate of NCF for the different regions modeled.

5.3 RENEWABLE TECHNOLOGY COST INPUTS

Black & Veatch developed capital and O&M costs for generic utility scale wind, utility scale solar photovoltaic (PV), and distributed Solar PV. These costs were developed based on our own market experience and project development experience, recent equipment supplier quotes, U.S. Department of Energy market assessment reports, reported costs of existing projects in the region, and some analysis of the existing VIWAPA PPA prices. For all technologies, where appropriate, adjustments have been made from domestic estimates to an island-based equivalent.

Capital costs represent total installed costs, including total engineering, procurement, and construction (EPC), owner's costs, and (for utility scale systems) interconnection costs. Operation and maintenance (O&M) costs for utility-scale wind and solar PV include scheduled and unscheduled maintenance and system monitoring, and assume a premium for maintaining smaller-scale projects on an island. Estimated costs for land leases and insurance are also included in the fixed O&M cost. Per USVI AB 7586, renewable energy systems are exempt from property tax but are considered as real property for insurance purposes, hence our O&M estimates have also excluded property tax. For distributed solar PV projects, we have assumed minimal maintenance and one inverter replacement over the project life.

For solar PV projects, we have provided both AC and DC capacity ratings in Table 5-16 are provided based on the assumed inverter loading ratios (ILR[3]). For fixed-tilt, single-axis tracking (SAT), and distributed PV projects we have assigned ILR's of 1.35, 1.25, and 1.1, respectively. Costs are somewhat sensitive to project size, as reflected in the different system sizes shown in Table 5-16. Utility-scale wind energy costs are assumed to be approximately flat for the range of project capacities identified for USVI.

The cost estimates in Table 5-16 have been used to develop levelized cost of energy (LCOE) estimates for input into the IRP production cost model. Financial inputs to the LCOE calculations have been made as appropriate, to be representative of renewable project development in USVI. These assumptions are shown in Appendix C.

[3] Inverter Loading Ratio (ILR) is the ratio of module rating (Wp) to Inverter rating (Wac), also known as the DC/AC ratio.

Table 5-16 Renewable Technology Cost Estimates

TECHNOLOGY	ILR [1]	PROJECT SIZE (KW AC)	PROJECT SIZE (KW DC)	CAPITAL COST ($/KW AC)	FIXED O&M COST ($/KWAC-YR)
Wind	NA	1,800[2]	NA	2,700	65
Wind	NA	275[3]	NA	4,700	65
Utility Scale PV (Fixed Tilt) [4]	1.35	1,000	1,350	3,950	60
Utility Scale PV (Fixed Tilt) [4]	1.35	5,000	6,750	3,550	60
Utility Scale PV (Single-Axis Tracking) [4]	1.25	1,000	1,250	4,100	65
Utility Scale PV (Single-Axis Tracking) [4]	1.25	5,000	6,250	3,700	65
Distributed PV	1.10	5	6	5,050	15
Distributed PV	1.10	20	22	4,750	15
Distributed PV	1.10	100	110	4,400	15
Distributed PV	1.10	500	550	4,000	15

(1) Inverter loading ratio = Module Rating (Wp) / Inverter Rating (Wac).
(2) Single Turbine Capacity shown. Representative of the Vestas V100, at utility scale project capacities.
(3) Single Turbine Capacity shown. Representative of the Vergnet GEV MP C, at distributed or medium scale project capacities.
(4) Based on simple terrain sites. Complex terrain sites are estimated to have 10 to 15 percent additional capital costs.
(5) Technical potential analysis and results are based on fixed-tilt systems; single-axis tracking systems are not addressed.

5.4 CONCLUSIONS AND RECOMMENDATIONS

Based on data provided by VIWAPA summarizing the existing and planned renewable energy projects (Table 5-1 and Table 5-2), the nameplate generating capacity from existing renewable sources currently represents approximately 28 MW, or 24 percent of the utility's peak load. This is already quite close to USVI's goal of 25 percent by 2020. The additional capacity for planned projects, all of which are planned for operation by the end of 2017, would increase generating capacity from renewables to 54 MW, or approximately 52 percent of the peak load (assuming no load growth), well above the 2025 goal of 30 percent.

USVI has set further goals regarding renewable generation, for example Act 7075 specifies the goal to increase "until a majority of energy is derived from renewables", and USVI has also signed a memorandum of understanding with the U.S. DOE establishing a goal of 60 percent of USVI energy needs from renewable sources.

Black & Veatch has identified a technical potential for wind and solar development in USVI, for a combined total estimated between 194 MW and 385 MW from rooftop PV, utility-scale PV, and utility-scale wind energy[4]. As mentioned in Appendix B, additional resources beyond those evaluated in this analysis could contribute to VIWAPA's generation mix, most notably a potential WTE plant on the order of 10 to 15 MW. Table 5-17 shows the estimated combined technical potentials from wind and solar.

---

[4] This combined total does not consider any limitation from overlapping wind and solar project areas, which could potentially reduce the high end of the range.

Table 5-17 Combined Technical Potential from Renewables

TECHNICAL POTENTIAL	LOW ESTIMATE (MW)	HIGH ESTIMATE (MW)
Rooftop PV(1)	127	203
Utility-Scale PV(2)	56	145
Utility-Scale Wind (3)	11	37
Total (4)	**194**	**385**

(1)Rooftop PV range based on system capacity limits, per Table 5-6.
(2)Utility-Scale PV range based on simple vs complex terrain results, per Table 5-8 and Table 5-9.
(3)Utility-Scale Wind range based on capacities for Vergnet and V100 turbines, per Table 5-12 and Table 5-13.
(4) Does not consider possible limitations due to overlapping project areas.

Based on these results, there is potential for significant additional generation from renewables. As stated in Section 0, these are the maximum technical potentials, and do not consider the challenges of grid integration, among other potential challenges or constraints that could be revealed upon more detailed review of any particular site.

Of the identified technical potential, Black & Veatch considers the most promising sites for near-term development to be utility-scale solar PV in simple terrain sites, and a utility-scale wind project on St. Croix to the east of the refinery ("Site #2"). Solar PV development in complex terrain is likely to be both more expensive and less productive than in simple terrain. Rooftop Solar PV does show a significant technical potential, however the integration of additional distributed generation beyond the current aggregate 15 MW VIWAPA limit may first require distribution system upgrades and/or the incorporation of energy storage solutions, adding to the overall cost of integration. A wind project at the identified Site #2 area on St. Croix appears to offer the least challenging path to development, while still exhibiting a productive wind resource and the potential for a relatively large project capacity.

As mentioned throughout the analysis, the lack of zoning and land use data has left some uncertainty with regard to the feasibility of identified land areas. Black & Veatch has developed reasonable assumptions to address this lack of data and has produced useful results; however, it is recommended that data be incorporated if and when it can be attained, to confirm the technical potential for renewables estimated in this analysis.

Black & Veatch recommends that the results of this potential analysis be incorporated into cost production modeling and grid integration modeling, to determine to what extent these resources may be economic, and what level of penetration is possible before grid upgrades are necessary.

6 Battery Energy Storage and Solar and Wind Generation

This section presents an overview of the current state of battery energy storage technologies (BESS) with a focus on lithium ion, BESS characteristics to consider, their costs, and operational capabilities.

6.1 UTILITY SCALE BATTERY ENERGY STORAGE OVERVIEW: TECHNOLOGIES AND OUTLOOK

The electric grid needs to balance supply and demand on a moment to moment basis. Energy commodities such as coal, oil, LPG, and natural gas can be readily stored in massive quantities. However, the storage of electricity has been relatively complex and expensive. Today, with the changing ways in which electricity is generated and used, increased penetration of renewable energy sources and distributed generation, and the smart grid are making energy storage more attractive than before.

Battery types employed within battery energy storage systems typically include lithium ion (Li-ion), lead-acid, sodium sulfur (NaS), and flow batteries. Most of the stationary energy storage activity in the industry is currently based on the lithium ion battery technology. Lithium ion batteries are the dominant player in battery energy storage, and their demonstrated experience is growing. Lithium ion batteries are projected to be a major industry player in the years to come and are well suited for both power and cycling applications as well as some energy applications. For these reasons, lithium ion was selected as the technology of analysis and in-depth overview for VIWAPA.

6.1.1 Energy Storage Overview and Outlook

Energy storage is becoming a more prevalent grid resource option in recent years as the need for more flexible capacity is emerging, both at the transmission and the distribution level. New policies in a number of states are driving growth in this sector through incentives or state requirements. Companies, such as Tesla Motors, an electric vehicle company, are seeking ways to mass produce batteries in order to drive costs down for both transportation and stationary applications. Many in the industry are forecasting a ten-fold or more increase in global market size in less than 10 years.

The U.S. energy storage market is expected to experience similar growth over the next few years. The market is being driven by renewables penetration and FERC order 755. Specifically, the energy storage mandate and Self Generation Incentive Program in California, and PJM pay-for-performance frequency regulation market have been the impetus for many of the early installations to date. Falling equipment prices, increasing supply and technical advances in addition to these market conditions have created the opportunity for storage to participate in the modern grid.

While energy storage was once thought to simply serve as a mechanism to time shift energy produced in off-peak hours, the market now recognizes a host of uses for energy storage. The challenge has become valuing the various services and properly incentivizing energy storage. In 2015, 84 percent of the energy storage deployed was in front of the meter. That percentage is expected to reduce over the coming years, as behind-the-meter applications rise.

Though pumped hydro historically dominates the energy storage market with a 95percent share, the current leading technology is Lithium Ion batteries, which accounted for 96 percent of energy storage deployments in 2015.

6.1.2 Battery Energy Storage System Technology Overview

Battery energy storage systems (BESS) employ multiple (up to several thousand) batteries that are connected in series and/or parallel, and are charged via an external source of electrical energy. The BESS discharges this stored energy to provide a specific electrical function.

A fully operational BESS comprises of an energy storage system that is combined with a bidirectional converter (also called a power conversion system). The BESS also contains a Battery Management System (BMS) and a Site or BESS Controller (Table 6-1).

Table 6-1 BESS Components

COMPONENT	DEFINITION
Energy Storage System (ESS)	The ESS consists of the battery modules or components as well as the racking, mechanical components and electrical connections between the various components.
Power Conversion System (PCS)	The PCS is a bi-directional converter that converts AC to DC and DC to AC. The PCS also communicates with the BMS and BESS controller.
Battery Management System (BMS)	The BMS can be comprised of various BMS units at the cell, module and system level. The BMS monitors and manages the battery state of charge (SOC) and charge and discharge of the ESS.
BESS/ Site Controller	The BESS controller communicates with all the components and is also the utility communication interface. Most of the advanced algorithms and control of the BESS resides in the BESS/ Site Controller.

When considering different energy storage technologies, there are a number of key performance parameters to understand:

- **Power Rating:** The rated power output (MW) of the entire ESS.
- **Energy Rating:** The energy storage capacity (MWh) of the entire ESS.
- **Discharge Duration:** The typical duration that the BESS can discharge at its power rating
- **Response Time:** How quickly an ESS can reach its power rating (typically in milliseconds).
- **Ramp-rate:** how quickly an energy storage system can change its power output, typically in MW/min
- **Charge/Discharge Rate (C-Rate):** A measure of the rate at which the ESS can charge/discharge relative to the rate at which will completely charge/discharge the battery in one hour. A one hour charge/ discharge rate is a 1C rate. Furthermore, a 2C rate completely charges/discharges the ESS in 30 minutes.

- **Round Trip Efficiency:** The amount of energy that can be discharged from an ESS relative to the amount of energy that went into the battery during charging (as a percentage). Typically stated at the point of interconnection and includes the ESS, PCS and transformer efficiencies.
- **Depth of Discharge (DOD):** The amount of energy discharged as a percentage of ESS overall energy rating.
- **State of Charge (SOC):** The amount of energy an ESS has charged relative to its energy rating, noted as a percentage.
- **Cycle Life:** Number of cycles before ESS reaches 80 percent (typical of lithium ion chemistries) of initial energy rating. The cycle life typically varies for various DODs.

These battery characteristics dictate how the batteries are configured and operated which will influence the appropriate sizing and economics and overall life of the systems.

6.1.3 Lithium Ion Batteries

Lithium ion batteries are a form of energy storage where all the energy is stored electrochemically within each cell. During charging or discharging, lithium ions are created and are the mechanism for charge transfer through the electrolyte of the battery. In general, these systems vary from vendor to vendor by the composition of the cathode or the anode. Some examples of cathode and anode combinations are shown in Figure 6-1.

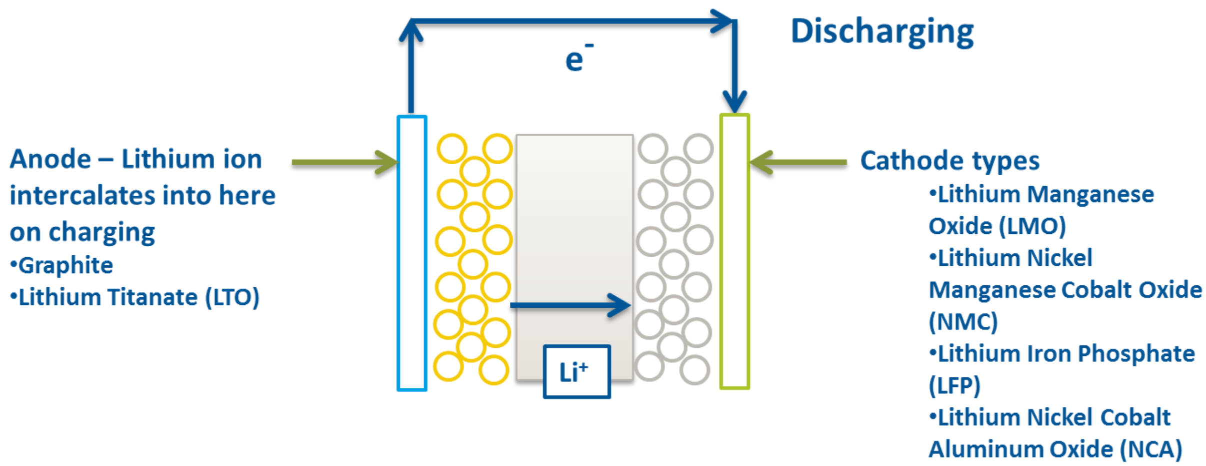


Figure 6-1 Lithium Ion Battery Showing Different Electrode Configurations

The battery cells are integrated to form modules. These modules are then strung together in series and/or parallel to achieve the appropriate power and energy rating to be coupled to the PCS.

Lithium ion battery energy storage systems are typically used for both power and energy applications. Lithium ion batteries have strong cycle life. For shallow, frequent cycles, which are quite common for power applications, lithium ion systems demonstrate good cycle life characteristics. Additionally, lithium ion systems demonstrate good cycle life characteristics for deeper discharges common for energy applications. Overall, this technology offers the following benefits:

- **Excellent Cycle Life**: Lithium ion technologies have superior cycling ability to other battery technologies such as lead acid.
- **Fast Response Time**: Lithium ion technologies have a fast response time which is typically less than 100 milliseconds.
- **High Round Trip Efficiency**: Lithium ion energy conversion is efficient and has ranges from the low 90s to high 90s for applications 4C-1/4C (DC-DC).
- **Versatility**: Lithium ion solutions can provide many relevant operating functions.
- **Commercial Availability**: There are many top tier lithium ion vendors.
- **Energy Density**: Lithium ion solutions have a high energy density to meet space constraints.

An image of a sample lithium ion BESS can be found in Figure 6-2.

Figure 6-2 Lithium Ion Battery Energy Storage System located at the Black & Veatch Headquarters

Various Li-ion battery systems are installed around the world, including projects in the United States. The 32 MW Laurel Mountain Project in West Virginia, the 32 MWh Tehachapi Project in California, and other projects in Chile and China employ Li-ion systems. According to the DOE Energy Storage Database, the United States installed (including under construction) capacity of Li-ion is about 291 MW and the worldwide installed (including under construction) capacity of Li-ion is about 672 MW.

Operation and Maintenance (O&M) activities for Li-Ion energy storage systems typically involve annual scheduled maintenance. During this maintenance, visual inspection of the system components and status check is performed as well as expendable parts such as filters are replaced. Software updates regarding BMS can be applied during this maintenance period.

6.1.3.1 Performance and Cost of Lithium Ion Batteries

Table 6-2 highlights some of the main performance parameters of lithium ion batteries. Many of the inputs were used in the solar plus storage analysis later on in the report.

Table 6-2 Representative Performance Parameters for Lithium Ion Battery Systems

PARAMETER	LI-ION
Facility Power Rating, MW1	0.005 to 32
Facility Energy Rating, MWh1	0.005 to 32
Ramp Rate, MW/min	Instantaneous
Response Time2	< 100 ms
Round-Trip Efficiency, percent (DC side)	90 to 98
Discharge Duration, hours	0.25 to 4
Charge/Discharge Rate, C3	C/4 to 4C
Cycle life, cycles at 80 percent DOD	1,200 to 5,000
Cycle life, cycles at 10percent DOD	60,000 to 200,000
ESS Cost, $/kWh4	450 to 650
Installed Capital Cost, $/kWh5	600 to 2000
Commercial Status6	Commercial
Fixed O&M Costs, $/kW-yr	5 to 10
Variable O&M Costs, $/kWh (charge or discharge)	0.001 to 0.005

Notes:

1. **The rating ranges shown are based on installed project sizes.**
2. **Amount of time system takes to reach rated power.**
3. **Charge/discharge rate is conventionally expressed in terms of “C-rate”. Under this convention, a system with a charge/discharge rate of 2C could be fully charged or discharged in 30 minutes (1/2 hour), while a system with a charge/discharge rate of 6C could be fully charged or discharged in 10 minutes (1/6 hour). Typically, lithium ion battery projects have been specified for C rates greater than C/4, however there are projects that have implemented systems with durations greater than 4 hours.**
4. **This cost refers to fabricated DC containers that is typically furnished by battery suppliers.**
5. **Battery cost scales with MWh, whereas balance of plant and PCS costs tend to scale with power (MW). Because of this and the wide range C rates lithium ion is able to perform, installed costs tend to have a wide array of values.**
6. **Black & Veatch considers technologies that have more than 5 installations and total installed operational capacity of more than 50 MW worldwide as commercial, less than 3 installations and total installed operational capacity of less than 10 MW as prototype, and in between as early commercial.**

6.2 ENERGY STORAGE APPLICATIONS

Energy storage has become an important grid resource in recent years at the transmission as well as the distribution level. Although it is not a generation resource, energy storage can perform many of the same applications as a traditional generator by using stored energy from the grid or from other distributed generation resources. These applications range from traditional uses such as providing capacity or ancillary services to more unique applications such as microgrids or renewable energy integration applications. A snapshot of various energy storage applications across the electric utility system can be found in Figure 6-3 at all scales—bulk system, transmission and distribution, and load.

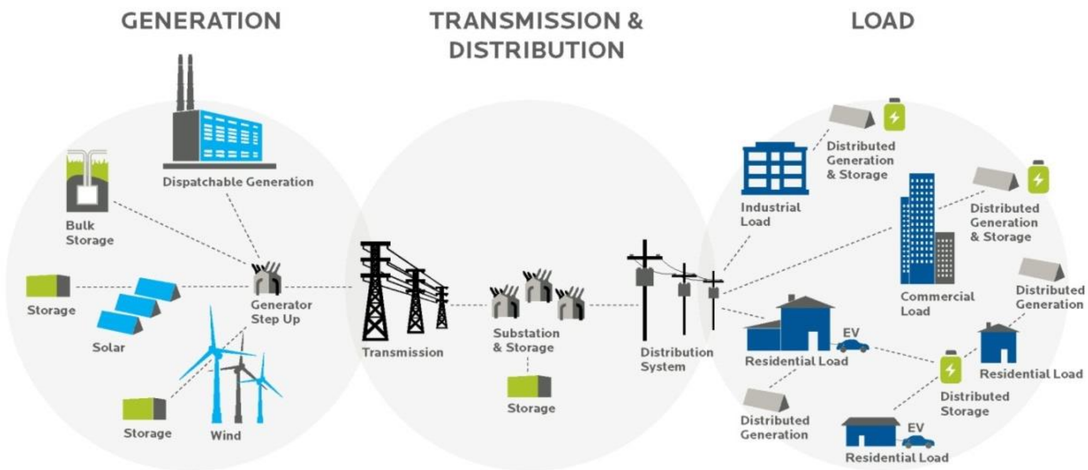


Figure 6-3 Energy Storage Applications across the Electric Utility System

Utility scale energy storage applications with their brief descriptions are provided below:

- **Electric Energy Time-Shift (Arbitrage):** The use of energy storage to purchase energy when prices are low and shift that energy to be sold when prices are higher (during peak times).
- **Peaking Supply:** The use of energy storage to provide system capacity during peak hours.
- **Frequency Regulation:** The use of energy storage to mitigate load and generation imbalances on the second to minute interval to maintain grid frequency.
- **Spinning Reserve:** The use of energy storage that is online and synchronized to supply generation capacity within 10 minutes.
- **Non-Spinning Reserve:** The use of energy storage that is offline but can be ramped up and synchronized to supply generation capacity within 10 minutes.
- **Voltage Support:** The energy storage converter can provide reactive power for voltage support and respond to voltage control signals from the grid.
- **Capacity Firming:** The use of energy storage to firm energy generation of a variable energy resource so that output reaches a specified level at certain times of the day.
- **Ramp Rate Control:** Ramp rate control can be used to limit the ramp rate of a variable energy resource to limit the impact to the grid.
- **Transmission Upgrade Deferral:** The use of energy storage to avoid or defer costly transmission upgrades.

Some of the applications listed above such as Ramp Rate Control or Capacity Firming may be coupled with variable renewable energy sources such as utility scale solar or wind generation to provide a more predictable net output to the grid. Other applications such as Electric Energy Time-

Shift or Frequency Regulation can be location independent and be performed at different locations on the grid.

These applications are often grouped into either power or energy applications. Power applications are generally shorter duration (approximately 15 minutes to one hour) applications that may involve frequent rapid responses or cycles. Frequency regulation or other renewable integration applications such as ramp rate control are good examples of power applications. Energy applications generally require longer duration (approximately 2 hours or more) energy storage systems. Electric Supply Capacity, Electric Energy Time-Shift, Capacity Firming, and Transmission Upgrade Deferral are examples of energy applications.

7 Resource Options Analysis

The VIWAPA electric systems on both the island of St. Croix and the islands of St. Thomas and St. John have near term need to improve the reliability of the electric system. In consideration of both the immediate need and continued desire for improved reliability, long term lowest cost, and fuel diversity to lower risk of dependence on a single fuel source, Black & Veatch in collaboration with VIWAPA considered the foregoing options to conclude recommendations for the going forward resource plan. The resource options analysis performed considered generation options to evaluate capacity and energy supply options associated with serving the power requirements on for the period through the year 2035.

The remainder of this section describes VIWAPA's electrical system load, generating facilities, and supply side options considered in detail for this study.

7.1 OPTIONS CONSIDERED

The technology options considered in the analysis are summarized below. Cost and performance characteristics for each technology class are summarized in Table 7-1, Table 7-2, Table 7-3 and Table 7-4.

1. Lease of block of three Wartsila reciprocating engines at St. Thomas. These units are currently available for installation at St. Thomas under a leasing arrangement.
2. Purchase of small generating units similar to Wartsila 20V34SG, a seven MW reciprocating engine and Solar Taurus 70, a seven MW combustion turbine.
3. GE TM2500+ lease
4. Siemens SGT-600
5. Refurbishment of HRSG Unit 21 and auxiliary equipment

Black & Veatch notes that the inclusion of specific manufacturer's names is not intended to be an implicit recommendation of final technology selection but rather to provide a representative example of a unit within a certain class of technologies. Black & Veatch recommends that VIWAPA issue requests for proposals for supply side options indicating a preference for generators nominally seven MW in size with multiple fuel capability and consider all qualified technology suppliers.

Table 7-1 Wartsila Engine Cost and Performance Characteristics, 2016$

WARTSILA 20V34SG			
Annual Lease Cost for set of Three Engines on 15 year lease, $/year	2,900,000		
Purchase Cost -Total Installed Cost Per Engine, $	8,432,400		
Variable O&M, $/MWh	13.68		
Fixed O&M, $/year/engine	429,490		
Forced Outage Rate	1%		
Scheduled Maintenance, hours/year	395		
Startup Energy Required, MMBtu	3.33		
% Loading	100%	75%	50%
Capacity, MW	7.027	5.250	3.470
Heat Rate, MMBtu/MWh	9.411	10.261	12.021
NOx Emission Rate, lbs/MMBtu	0.0172	0.0158	0.0154

Table 7-2 GE TM2500+ Cost and Performance Characteristics, 2016$

GE TM2500			
Annual Lease Cost, $/year	8,040,000		
Variable O&M, $/MWh	Included in Lease Cost		
Fixed O&M, $/year	Included in Lease Cost		
Forced Outage Rate	2%		
Scheduled Maintenance, hours/year	672		
Startup Energy Required, MMBtu	3.49		
% Loading	100%	75%	30%
Capacity, MW	23.22	17.41	6.96
Heat Rate, MMBtu/MWh	11.986	12.665	18.404
NOx Emission Rate, lbs/MMBtu	0.1458		

Table 7-3 Siemens SGT-600 Cost and Performance Characteristics, 2016$

SIEMENS SGT-600			
Total Installed Cost, $	10,890,248		
Variable O&M, $/MWh	6.08		
Fixed O&M, $/year	672,041		
Forced Outage Rate	2%		
Scheduled Maintenance, hours/year	672		
Startup Energy Required, MMBtu	4.0		
% Loading	100%	75%	30%
Capacity, MW	21.98	16.49	6.59
Heat Rate, MMBtu/MWh	11.641	12.301	17.875
NOx Emission Rate, lbs/MMBtu	0.1251		

Table 7-4 Solar Taurus 70 Cost and Performance Characteristics, 2016$

SOLAR TAURUS 70			
Total Installed Cost, $	5,670,000		
Variable O&M, $/MWh	7.93		
Fixed O&M, $/year	32,000		
Forced Outage Rate	1.71%		
Scheduled Maintenance, hours/year	240		
Startup Energy Required, MMBtu	3.33		
% Loading	100%	75%	50%
Capacity, MW	6.716	5.037	3.358
Heat Rate, MMBtu/MWh	10.581	11.571	13.580
NOx Emission Rate, lbs/MMBtu	0.90		

7.2 PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

For this analysis, it has been assumed that annual peak demand and annual energy sales will not increase through the end of the analysis period. General inflation is assumed to be 1.5 percent per year. The present worth discount rate assumed is 5.25 percent. Bond Interest Rate for a 30-year bond is assumed to be 5.5% and for a 20 year bond is assumed to be 5.00%. Bond issuance fee is 1.50%.

The technologies, fuel type, rated capacity, availability, heat rate data, and O&M costs associated with the VIWAPA's existing generating resources used in this analysis are based on information provided by VIWAPA.

7.2.1 Electric Demand Summary

The monthly and annual VIWAPA demand forecast used in the Study is shown in Table 7-5. As stated previously, the forecast demand is assumed to remain unchanged for all years of the analysis.

Table 7-5 Monthly Demand and Energy Forecast, 2016

	ST CROIX				ST THOMAS			
	Total Energy, GWh	Peak Demand, MW	Average Demand, MW	Load Factor	Total Energy, GWh	Peak Demand, MW	Average Demand, MW	Load Factor
January	23.303	35.300	31.322	88.7%	34.869	56.440	46.867	83.0%
February	21.234	36.290	30.509	84.1%	30.701	55.430	44.111	79.6%
March	23.628	35.430	31.758	89.6%	33.927	55.150	45.601	82.7%
April	22.731	35.320	31.571	89.4%	32.821	56.810	45.585	80.2%
May	23.620	35.530	31.747	89.4%	33.675	56.170	45.262	80.6%
June	23.901	38.000	33.196	87.4%	33.524	60.600	46.561	76.8%
July	25.035	36.350	33.649	92.6%	37.389	62.000	50.253	81.1%
August	25.077	36.730	33.706	91.8%	36.135	59.490	48.569	81.6%
September	24.434	37.140	33.935	91.4%	35.376	60.090	49.134	81.8%
October	25.574	37.190	34.374	92.4%	36.281	59.680	48.764	81.7%
November	23.247	36.560	32.288	88.3%	34.426	59.580	47.814	80.3%
December	23.717	35.910	31.878	88.8%	34.976	57.270	47.011	82.1%
Annual	**285.503**	**38.000**	**32.503**	**85.5%**	**414.100**	**62.000**	**47.143**	**76.0%**

7.2.2 Emissions Allowance Price Projections

VIWAPA provided emission allowance price projections. The USVI Department of Planning and Natural Resources (DPNR) sets the emission rates per ton and it has been $50 per ton for both nitrogen oxides (NO_x) and sulfur dioxide (SO_2) for several years. It was assumed that the rates will remain at $50/ton in real terms throughout the study period. The US Environmental Protection Agency (EPA) has not published carbon dioxide (CO_2) target rates for the Virgin Islands and therefore the assumed cost for CO_2 emissions is zero.

7.3 CASE ANALYSIS RESULTS

Several alternative cases were developed and compared to determine the recommended plans at St. Thomas and St. Croix. The cases consisted of retiring existing generation and adding new generation. A detailed discussion of the plans that resulted in lowest cost while simultaneously meeting the objectives of system reliability and dual fuel capability are described in Table 7-6.

Table 7-6 Descriptions of Lowest cost plans meeting reliability and dual fuel criteria.

ST. THOMAS PLANS			
Option 0	Case 3Slr	Case 3Slr 12M	Case 3Slr 12M var

Refurbishment of HRSG Unit 21 at STT, continued operation of existing units.	1. Extend lease contract for Unit 25 for 6 months. 2. Lease GE TM2500+ beginning January 2017 for one year and Retire STT 14 in March 2017 3. Lease 3 Wartsila 20V34SG units beginning October 2017 4. Add 3 Solar Taurus 70 in March 2018 5. Add 3 Wartsila 20V34SG units beginning October 2018 and retire Unit 23 in June 2019 6. Add 3 Solar Taurus 70 in October 2019 7. Add 3 Solar Taurus 70 in October 2020 and retire Unit 18 in December 2020.	1. Extend lease contract for Unit 25 for 12 months. 2. Lease GE TM2500+ beginning January 2017 for one year and Retire STT 14 in March 2017 3. Lease 3 Wartsila 20V34SG units beginning October 2017 4. Add 3 Solar Taurus 70 in March 2018 5. Add 3 Wartsila 20V34SG units beginning October 2018 and retire Unit 23 in June 2019 6. Add 3 Solar Taurus 70 in October 2019 7. Add 3 Solar Taurus 70 in October 2020 and retire Unit 18 in December 2020.	1. Same as Case 3Slr 12M except Unit 25 contract extension is based on Fired Hour Rate as proposed in APR proposal dated 05 October 2016.

ST. CROIX PLANS		
Option 0 STX	**Case 3Slr STX**	**Case 3SlrW STX**
1.) Continued operation of existing unit	1. Add 3 Solar Taurus 70 in October 2018 2. Retire Unit 19 in December 2018. 3. Add 3 Wartsila 20V34SG units in October 2019 at new site. 4. Retire Unit 17 in December 2019 5. Add 2 Solar Taurus 70 units in October 2020 6. Retire Unit 16 in December 2020 7. Add 1 Solar Taurus 70 in October 2022 8. Retire Unit 20 in December 2022	1. Add 3 Solar Taurus 70 in October 2018 2. Retire Unit 19 in December 2018. 3. Add 3 Wartsila 20V34SG units in October 2019 at new site. 4. Retire Unit 17 in December 2019 5. Add 2 Solar Taurus 70 units in October 2020 6. Retire Unit 16 in December 2020 7. Add 1 Wartsila 20V34SG unit in October 2022 8. Retire Unit 20 in December 2022

Based on an hourly production cost methodology using the ProMod production cost simulator, and the principal considerations and assumptions as described above, the projected total system costs were derived for the five cases summarized in Table 7-7 in comparison to continued operation of the existing system. The total costs for each option are summarized in **Error! Reference source not found.Error! Reference source not found.**.

The major components to the Cumulative Present Worth Costs (CPWC) for all cases are also shown in Figure 7-1 and Figure 7-2. Detailed annual costs and CPWC are provided in Appendix A.

Table 7-7 Annual System Costs ($1000)

YEAR	OPTION 0 STT	CASE 3SLR	CASE 3SLR 12M	CASE 3SLR 12M VAR	OPTION 0 STX	CASE 3SLR STX	CASE 3SLRW STX
2016	$84,546	$85,245	$84,955	$85,641	$53,132	$53,132	$53,253
2017	$98,135	$87,491	$89,505	$95,938	$52,766	$52,766	$53,249
2018	$75,712	$82,387	$82,387	$82,387	$57,043	$54,280	$54,763
2019	$81,543	$77,013	$77,013	$77,013	$63,142	$53,561	$54,044
2020	$91,543	$84,377	$84,377	$84,377	$72,203	$57,071	$57,426
2021	$93,971	$84,661	$84,661	$84,661	$75,234	$58,121	$58,092
2022	$96,102	$83,165	$83,165	$83,165	$77,602	$64,181	$64,089
2023	$98,487	$84,426	$84,426	$84,426	$79,318	$64,426	$64,288
2024	$101,084	$85,829	$85,829	$85,829	$80,490	$65,164	$65,033
2025	$103,706	$87,301	$87,301	$87,301	$82,013	$65,919	$65,750
2026	$105,305	$88,803	$88,803	$88,803	$82,409	$66,681	$66,504
2027	$108,119	$90,299	$90,299	$90,299	$83,483	$67,451	$67,254
2028	$108,841	$91,482	$91,482	$91,482	$84,854	$68,035	$67,846
2029	$109,508	$93,037	$93,037	$93,037	$86,667	$68,831	$68,629
2030	$113,228	$94,683	$94,683	$94,683	$88,373	$69,697	$69,449
2031	$115,584	$96,341	$96,341	$96,341	$89,420	$70,525	$70,270
2032	$118,554	$97,106	$97,106	$97,106	$90,567	$71,344	$71,092
2033	$120,101	$96,225	$96,225	$96,225	$91,379	$72,253	$71,952
2034	$121,785	$97,981	$97,981	$97,981	$92,091	$73,114	$72,839
2035	$125,044	$99,304	$99,304	$99,304	$94,479	$73,804	$73,514
2036	$127,283	$101,130	$101,130	$101,130	$96,235	$74,749	$74,317
21-yr CPWC	**$1,328,543**	**$1,164,423**	**$1,166,046**	**$1,172,845**	**$1,001,060**	**$829,838**	**$829,902**

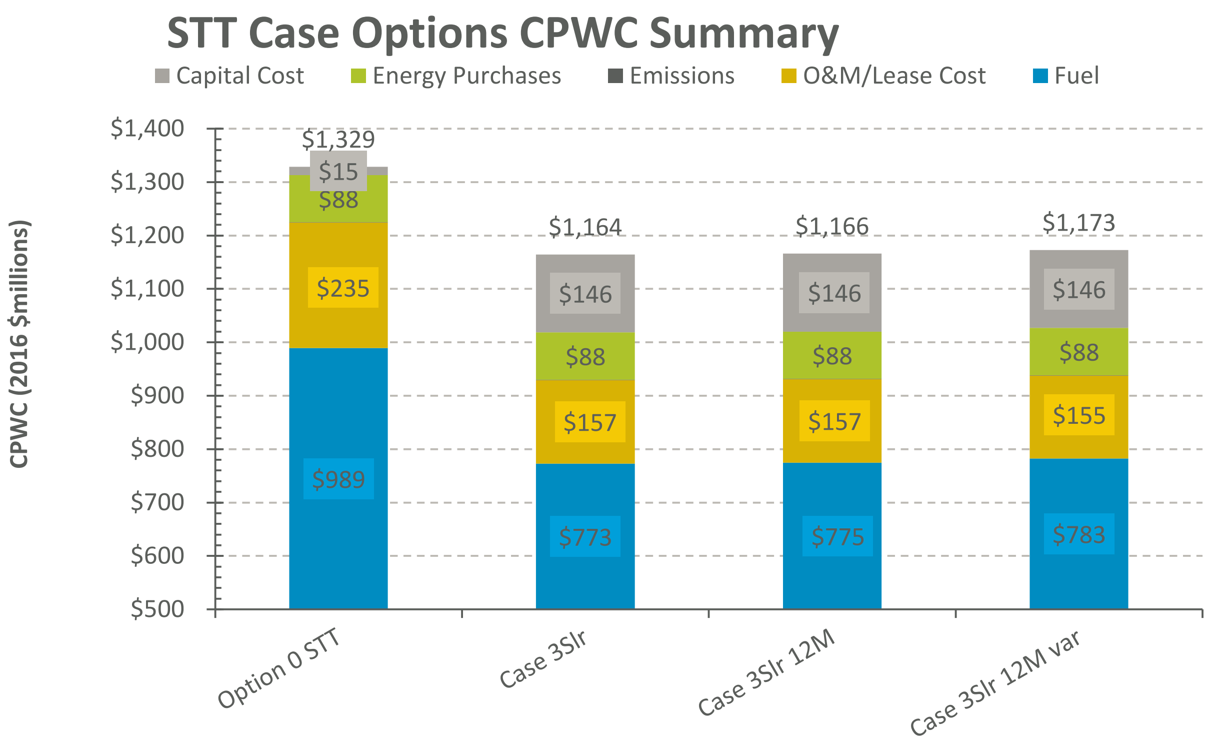


Figure 7-1 Major Components of CPWC for STT Case Options

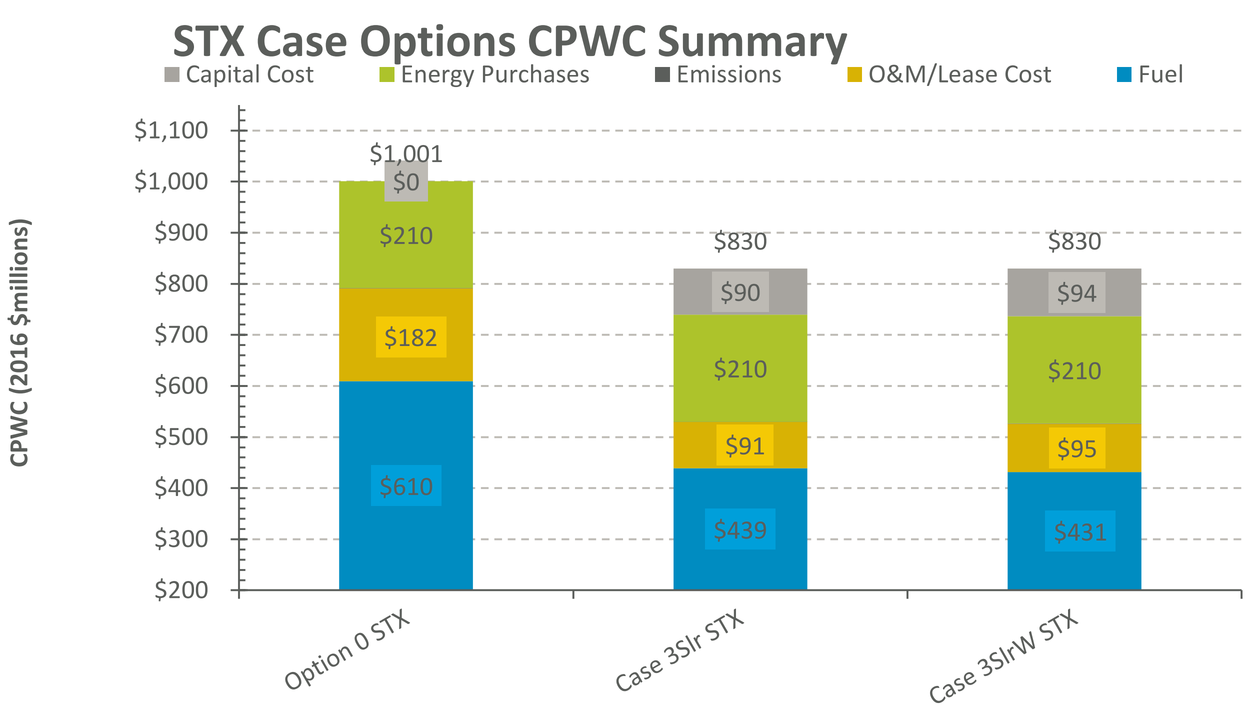


Figure 7-2 Major Components of CPWC for STX Case Options

For St. Thomas, APR provided a proposal for the extension of the existing TM2500 lease and a 12 month lease option for a LPG-fired TM2500+. The proposal is dated October 5, 2016 and contains three options for a lease extension of the existing TM2500 diesel generator. Of the three options provided for the TM2500 lease extension, the plan with the 12 month contract extension with the monthly rental fee is the recommended plan. For St. Croix, Case 3Slr STX, the plan with the Solar Taurus unit rather than the Wartsila unit is the recommended plan.

8 Avoided Costs

8.1 AVOIDED COST

The concept of avoided costs in the electric utility industry arises from the federal legislation of the 1970s known as PURPA (Public Utility Regulatory Policies Act. PURPA was enacted to encourage alternative energy development by providing qualified facility (QF) status to eligible cogeneration and small renewables with rights to sell to utilities whilst maintaining ratepayer neutrality.

In the context of a traditional utility, avoided cost may be defined based on the definition promulgated by the Federal Energy Regulatory Commission (FERC): avoided costs are the "incremental costs to an electric utility of electric energy or capacity which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source" (18 CFR §292.101(b)).

The concept of the FERC definition of avoided cost is similar to the definition of marginal costs: i.e., "marginal cost equals the increase in total Cost divided by the increase in output". In other words, the production of the last kilowatt of electricity increases the utility's cost of operation by a (small) amount, and that amount is its avoided cost if it does not have to produce the extra kilowatt.

The remainder of this section describes VIWAPA's electrical system load and generating facilities, and the methodology used to forecast the avoided capacity and energy costs.

8.2 PRINCIPAL CONSIDERATIONS AND ASSUMPTIONS

Based on discussions with VIWAPA, it has been assumed that demand and energy sales will remain flat through 2035 on the islands of St. Thomas and St. Croix. General inflation is assumed to be 1.5 percent per year. The present worth discount rate assumed is 3.5 percent. The technologies, fuel type, rated capacity, availability, heat rate data, and O&M costs associated with the VIWAPA's existing generating resources used in the Avoided Cost Study are based on information provided by VIWAPA.

8.2.1 Electric Demand Summary

The monthly and annual VIWAPA demand forecast used in the Avoided Costs Study is shown in Table 8-1. As stated previously, the forecast demand is assumed to remain unchanged for all years of the analysis.

Table 8-1 Monthly Demand and Energy Forecast, 2016

	ST CROIX				ST THOMAS			
	Total Energy, GWh	Peak Demand, MW	Average Demand, MW	Load Factor	Total Energy, GWh	Peak Demand, MW	Average Demand, MW	Load Factor
January	23.303	35.300	31.322	88.7%	34.869	56.440	46.867	83.0%
February	21.234	36.290	30.509	84.1%	30.701	55.430	44.111	79.6%
March	23.628	35.430	31.758	89.6%	33.927	55.150	45.601	82.7%
April	22.731	35.320	31.571	89.4%	32.821	56.810	45.585	80.2%
May	23.620	35.530	31.747	89.4%	33.675	56.170	45.262	80.6%
June	23.901	38.000	33.196	87.4%	33.524	60.600	46.561	76.8%
July	25.035	36.350	33.649	92.6%	37.389	62.000	50.253	81.1%
August	25.077	36.730	33.706	91.8%	36.135	59.490	48.569	81.6%
September	24.434	37.140	33.935	91.4%	35.376	60.090	49.134	81.8%
October	25.574	37.190	34.374	92.4%	36.281	59.680	48.764	81.7%
November	23.247	36.560	32.288	88.3%	34.426	59.580	47.814	80.3%
December	23.717	35.910	31.878	88.8%	34.976	57.270	47.011	82.1%
Annual	**285.503**	**38.000**	**32.503**	**85.5%**	**414.100**	**62.000**	**47.143**	**76.0%**

8.2.2 Emissions Allowance Price Projections

VIWAPA provided emission allowance price projections. The USVI Department of Planning and Natural Resources (DPNR) sets the emission rates per ton and it has been $50 per ton for both nitrogen oxides (NO_x) and sulfur dioxide (SO_2) for several years. It was assumed that the rates will remain at $50/ton in real terms throughout the study period. The US Environmental Protection Agency (EPA) has not published carbon dioxide (CO_2) target rates for the Virgin Islands and therefore the assumed cost for CO_2 emissions is zero.

8.2.3 Avoided Capacity and Energy Cost Methodology

Since no additional capacity requirements are projected for either St. Thomas or St. Croix through the remainder of the study period there is no projected avoided cost associated with capacity.

With respect to avoided energy costs, the forecast avoided costs were determined based on a marginal cost methodology. The avoided energy cost for each year is based on the average marginal costs each hour of the year for both the St. Croix and St. Thomas service territories calculated separately. This avoided energy cost is the cost of energy for the first unit of energy replaced. Theory of marginal cost dictates that each additional incremental amount of energy that would be displaced by potential resources will be of equal or lower cost. When on-line dispatchable generating resources are reduced to minimum levels the marginal cost reduces to zero during that timeframe because the system has no capacity to accommodate additional generation and maintain normally recognized reliability constraints (e.g., spinning reserve requirements) and hence there is not avoided cost associated with potential replacement energy.

Forecast avoided costs for St. Croix and St. Thomas for the recommended plans for both St. Thomas and St. Croix are shown below.

Table 8-2 Average Annual System Avoided Costs ($/MWh)

YEAR	STT: CASE 3SLR 12M			STX: CASE 3SLR STX		
	RTC Average	PV average	Wind average	RTC Average	PV average	Wind average
2016	105.18	109.20	111.64	168.19	157.59	159.28
2017	116.18	135.34	131.94	190.87	197.65	203.15
2018	128.17	128.92	159.11	199.03	191.31	199.71
2019	128.29	123.46	124.97	174.95	137.12	201.79
2020	149.84	145.64	148.31	157.77	139.03	158.44
2021	149.64	145.05	146.82	158.84	138.93	155.52
2022	151.96	148.67	150.05	150.51	134.71	149.40
2023	156.13	152.88	154.36	150.20	138.16	149.07
2024	159.56	156.41	157.41	153.39	141.86	152.40
2025	163.25	160.26	161.14	156.73	144.04	155.37
2026	166.91	163.67	164.87	160.24	147.58	159.09
2027	170.37	166.99	168.34	163.94	150.98	162.84
2028	173.02	169.41	170.60	166.12	152.81	164.96
2029	177.08	173.42	174.60	170.14	156.54	168.70
2030	180.97	177.14	178.27	173.93	160.43	172.42
2031	184.90	181.40	182.30	177.52	163.07	175.85
2032	188.81	184.97	186.42	181.37	167.19	179.75
2033	193.02	188.46	190.27	185.88	171.39	183.92
2034	197.26	193.35	194.56	189.77	174.54	187.73
2035	200.71	196.50	197.79	192.92	177.21	190.91
20-yr avg	162.06	160.06	162.69	171.12	157.11	171.51

Appendix A. CPWC Tables

Option 0 STT

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions

Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
HRSG 21 System	16,000	0	1	01/01/2017		16,000

	Energy Balance					Production Cost						Total					Cumulative
					Loss		Plant O&M			Total		Production			Unit Additions	Total	Present
				Curtailed	of	Fuel				Generation		Costs plus	Generation		Capital	System	Worth
Year	Load	Generation	Purchases	Load	Load	Cost	Variable	Fixed	Emissions	Cost	Purchases	Purchases	Cost	Purchases	Costs	Cost	Cost
	(GWh)	(GWh)	(GWh)	(GWh)	Hours	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1000)	($1000)	($/MWh)	($/MWh)	($1,000)	($1,000)	($1,000)
2016	414.1	390.2	23.9	0.10	21.0	$62,037	$1,623	$18,774	$36	$82,471	$2,075	$84,546	$211.38	$87.01	$0	$84,546	$84,546
2017	414.1	386.4	25.8	1.91	141.0	$54,378	$2,747	$22,872	$27	$80,025	$2,110	$82,135	$207.10	$81.87	$16,000	$98,135	$177,786
2018	414.1	383.4	28.6	2.14	403.0	$56,372	$4,190	$12,553	$28	$73,143	$2,569	$75,712	$190.77	$89.88	$0	$75,712	$246,133
2019	414.1	383.1	28.6	2.43	517.0	$62,875	$4,403	$11,647	$41	$78,967	$2,576	$81,543	$206.12	$90.14	$0	$81,543	$316,072
2020	414.1	381.5	28.7	3.92	427.0	$73,069	$4,835	$10,997	$50	$88,952	$2,591	$91,543	$233.16	$90.39	$0	$91,543	$390,671
2021	414.1	373.5	33.6	7.05	345.0	$74,694	$4,826	$11,162	$51	$90,733	$3,238	$93,971	$242.93	$96.44	$0	$93,971	$463,430
2022	414.1	334.0	75.6	4.52	275.0	$71,474	$4,395	$11,330	$47	$87,245	$8,857	$96,102	$261.23	$117.15	$0	$96,102	$534,126
2023	414.1	333.5	75.6	4.94	306.0	$73,538	$4,438	$11,500	$49	$89,525	$8,962	$98,487	$268.43	$118.51	$0	$98,487	$602,964
2024	414.1	335.1	75.8	3.14	315.0	$75,746	$4,528	$11,672	$48	$91,994	$9,089	$101,084	$274.51	$119.88	$0	$101,084	$670,092
2025	414.1	336.3	75.6	2.14	193.0	$78,018	$4,622	$11,847	$48	$94,536	$9,170	$103,706	$281.09	$121.26	$0	$103,706	$735,526
2026	414.1	333.8	75.6	4.69	234.0	$79,294	$4,660	$12,025	$50	$96,029	$9,276	$105,305	$287.70	$122.67	$0	$105,305	$798,655
2027	414.1	336.7	75.6	1.74	229.0	$81,722	$4,758	$12,205	$50	$98,735	$9,384	$108,119	$293.23	$124.10	$0	$108,119	$860,238
2028	414.1	336.5	75.8	1.70	168.0	$82,038	$4,845	$12,389	$50	$99,322	$9,519	$108,841	$295.13	$125.55	$0	$108,841	$919,139
2029	414.1	328.6	75.6	9.87	467.0	$82,495	$4,778	$12,574	$56	$99,903	$9,605	$109,508	$304.06	$127.02	$0	$109,508	$975,446
2030	414.1	334.6	75.6	3.85	252.0	$85,737	$4,958	$12,763	$53	$103,510	$9,718	$113,228	$309.34	$128.51	$0	$113,228	$1,030,761
2031	414.1	335.0	75.6	3.44	225.0	$87,688	$5,056	$12,954	$52	$105,751	$9,833	$115,584	$315.67	$130.03	$0	$115,584	$1,084,411
2032	414.1	335.6	75.8	2.68	270.0	$90,258	$5,118	$13,149	$53	$108,578	$9,976	$118,554	$323.55	$131.57	$0	$118,554	$1,136,694
2033	414.1	334.4	75.6	4.09	265.0	$91,445	$5,188	$13,346	$54	$110,034	$10,067	$120,101	$329.06	$133.13	$0	$120,101	$1,187,018
2034	414.1	331.2	75.6	7.26	277.0	$92,775	$5,220	$13,546	$57	$111,597	$10,187	$121,785	$336.94	$134.72	$0	$121,785	$1,235,501
2035	414.1	334.0	75.6	4.50	328.0	$95,616	$5,312	$13,749	$58	$114,735	$10,309	$125,044	$343.55	$136.33	$0	$125,044	$1,282,799
2036	414.1	332.2	75.8	6.13	322.0	$97,435	$5,373	$13,956	$58	$116,823	$10,460	$127,283	$351.72	$137.96	$0	$127,283	$1,328,543
					Levelized Cost($1000):	$74,921	$4,357	$13,453	$46	$92,778	$6,701	$99,479	$265	$111	$1,151	$100,630	
					NPV:	$989,125	$57,528	$177,610	$610	$1,224,872	$88,469	$1,313,341	$3,499	$1,466	$15,202	$1,328,543	
					Levelized Cost($/MWh):	$135.32	$7.87	$24.30	$0.08	$167.57	$67.84	$151.02	$166.62	$69.81	$2.08	$152.77	

Notes:

Case 3slr Solar Taurus 70

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions

Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
STT 3 Wartsila 15-yr Lease	39,650	0	15	10/01/2017	40,747	3,474
3x Solar Taurus 70	16,650	6	20	03/01/2018	17,353	1,479
Infrasture Costs (Including T&D)	55,000	1	30	01/01/2019	57,635	4,148
STT 3 Wartsila	25,297	6	20	10/01/2018	26,628	2,270
3x Solar Taurus 70	16,650	6	20	10/01/2019	17,789	1,517
3x Solar Taurus 70	16,650	6	20	10/01/2020	18,055	1,539

Year	Energy Balance: Load (GWh)	Energy Balance: Generation (GWh)	Energy Balance: Purchases (GWh)	Energy Balance: Curtailed Load (GWh)	Loss of Load Hours	Production Cost: Fuel Cost ($1,000)	Production Cost: Plant O&M Variable ($1,000)	Production Cost: Plant O&M Fixed ($1,000)	Production Cost: Emissions ($1,000)	Total Generation Cost ($1,000)	Purchases ($1000)	Total Production Costs plus Purchases ($1000)	Generation Cost ($/MWh)	Purchases ($/MWh)	Unit Additions Capital Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2016	414.1	390.2	23.9	0.000	0.0	$62,401	$1,666	$19,064	$38	$83,169	$2,075	$85,245	$213.13	$87.01	$0	$85,245	$85,245
2017	414.1	384.8	25.8	3.579	279.0	$61,005	$2,270	$21,211	$27	$84,513	$2,110	$86,623	$219.64	$81.87	$869	$87,491	$168,372
2018	414.1	385.5	28.6	0.081	19.0	$57,492	$4,452	$12,565	$35	$74,544	$2,569	$77,113	$193.39	$89.88	$5,275	$82,387	$242,745
2019	414.1	385.5	28.6	0.001	2.0	$46,878	$4,982	$10,800	$26	$62,686	$2,576	$65,262	$162.60	$90.14	$11,751	$77,013	$308,799
2020	414.1	385.5	28.7	0.000	0.0	$55,103	$5,027	$8,354	$27	$68,512	$2,591	$71,104	$177.74	$90.39	$13,273	$84,377	$377,559
2021	414.1	380.6	33.6	0.000	0.0	$56,046	$4,861	$6,055	$33	$66,995	$3,238	$70,233	$176.05	$96.44	$14,428	$84,661	$443,109
2022	414.1	338.5	75.6	0.000	0.0	$51,826	$4,350	$3,674	$31	$59,880	$8,857	$68,737	$176.91	$117.15	$14,428	$83,165	$504,289
2023	414.1	338.5	75.6	0.000	0.0	$53,362	$4,416	$3,227	$31	$61,036	$8,962	$69,998	$180.34	$118.51	$14,428	$84,426	$563,298
2024	414.1	338.3	75.8	0.000	0.0	$54,527	$4,478	$3,275	$32	$62,312	$9,089	$71,401	$184.22	$119.88	$14,428	$85,829	$620,296
2025	414.1	338.5	75.6	0.000	0.0	$55,797	$4,550	$3,325	$32	$63,703	$9,170	$72,873	$188.22	$121.26	$14,428	$87,301	$675,380
2026	414.1	338.5	75.6	0.000	0.0	$57,074	$4,618	$3,374	$33	$65,099	$9,276	$74,375	$192.34	$122.67	$14,428	$88,803	$728,616
2027	414.1	338.5	75.6	0.000	0.0	$58,341	$4,688	$3,425	$33	$66,487	$9,384	$75,871	$196.44	$124.10	$14,428	$90,299	$780,049
2028	414.1	338.3	75.8	0.000	0.0	$59,275	$4,750	$3,476	$34	$67,534	$9,519	$77,054	$199.66	$125.55	$14,428	$91,482	$829,556
2029	414.1	338.5	75.6	0.000	0.0	$60,610	$4,831	$3,529	$34	$69,004	$9,605	$78,609	$203.88	$127.02	$14,428	$93,037	$877,393
2030	414.1	338.5	75.6	0.000	0.0	$62,020	$4,900	$3,581	$35	$70,536	$9,718	$80,255	$208.41	$128.51	$14,428	$94,683	$923,649
2031	414.1	338.5	75.6	0.000	0.0	$63,439	$4,970	$3,635	$35	$72,080	$9,833	$81,913	$212.97	$130.03	$14,428	$96,341	$968,366
2032	414.1	338.3	75.8	0.000	0.0	$64,803	$5,043	$3,690	$36	$73,571	$9,976	$83,547	$217.50	$131.57	$13,559	$97,106	$1,011,191
2033	414.1	338.5	75.6	0.000	0.0	$66,297	$5,125	$3,745	$36	$75,204	$10,067	$85,271	$222.20	$133.13	$10,954	$96,225	$1,051,510
2034	414.1	338.5	75.6	0.000	0.0	$67,803	$5,199	$3,801	$37	$76,840	$10,187	$87,027	$227.03	$134.72	$10,954	$97,981	$1,090,517
2035	414.1	338.5	75.6	0.000	0.0	$68,865	$5,280	$3,858	$37	$78,041	$10,309	$88,350	$230.58	$136.33	$10,954	$99,304	$1,128,079
2036	414.1	338.3	75.8	0.000	0.0	$70,412	$5,350	$3,916	$38	$79,716	$10,460	$90,176	$235.67	$137.96	$10,954	$101,130	$1,164,423
Levelized Cost($1000):						$58,531	$4,368	$7,516	$33	$70,448	$6,701	$77,149	$197	$111	$11,050	$88,199	
NPV:						$772,742	$57,662	$99,233	$432	$930,069	$88,469	$1,018,538	$2,606	$1,466	$145,885	$1,164,423	
Levelized Cost($/MWh):						$104.59	$7.80	$13.43	$0.06	$125.89	$67.84	$117.12	$124.11	$69.81	$19.75	$133.90	

Notes:

Case 3slr 12M Solar Taurus 70

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions

Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
STT 3 Wartsila 15-yr Lease	39,650	0	15	10/01/2017	40,747	3,474
3x Solar Taurus 70	16,650	6	20	03/01/2018	17,353	1,479
Infrasture Costs (Including T&D)	55,000	1	30	01/01/2019	57,635	4,148
STT 3 Wartsila	25,297	6	20	10/01/2018	26,628	2,270
3x Solar Taurus 70	16,650	6	20	10/01/2019	17,789	1,517
3x Solar Taurus 70	16,650	6	20	10/01/2020	18,055	1,539

Year	Energy Balance: Load (GWh)	Energy Balance: Generation (GWh)	Energy Balance: Purchases (GWh)	Energy Balance: Curtailed Load (GWh)	Loss of Load Hours	Production Cost: Fuel Cost ($1,000)	Production Cost: Plant O&M Variable ($1,000)	Production Cost: Plant O&M Fixed ($1,000)	Production Cost: Emissions ($1,000)	Total Generation Cost ($1,000)	Purchases ($1000)	Total Production Costs plus Purchases ($1000)	Generation Cost ($/MWh)	Purchases ($/MWh)	Unit Additions Capital Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2016	414.1	390.2	23.9	0.000	0.0	$62,401	$1,666	$18,774	$38	$82,879	$2,075	$84,955	$212.39	$87.01	$0	$84,955	$84,955
2017	414.1	387.8	25.8	0.530	79.0	$63,076	$1,740	$21,681	$29	$86,526	$2,110	$88,636	$223.12	$81.87	$869	$89,505	$169,995
2018	414.1	385.5	28.6	0.081	19.0	$57,492	$4,452	$12,565	$35	$74,544	$2,569	$77,113	$193.39	$89.88	$5,275	$82,387	$244,368
2019	414.1	385.5	28.6	0.001	2.0	$46,878	$4,982	$10,800	$26	$62,686	$2,576	$65,262	$162.60	$90.14	$11,751	$77,013	$310,422
2020	414.1	385.5	28.7	0.000	0.0	$55,103	$5,027	$8,354	$27	$68,512	$2,591	$71,104	$177.74	$90.39	$13,273	$84,377	$379,182
2021	414.1	380.6	33.6	0.000	0.0	$56,046	$4,861	$6,055	$33	$66,995	$3,238	$70,233	$176.05	$96.44	$14,428	$84,661	$444,732
2022	414.1	338.5	75.6	0.000	0.0	$51,826	$4,350	$3,674	$31	$59,880	$8,857	$68,737	$176.91	$117.15	$14,428	$83,165	$505,912
2023	414.1	338.5	75.6	0.000	0.0	$53,362	$4,416	$3,227	$31	$61,036	$8,962	$69,998	$180.34	$118.51	$14,428	$84,426	$564,921
2024	414.1	338.3	75.8	0.000	0.0	$54,527	$4,478	$3,275	$32	$62,312	$9,089	$71,401	$184.22	$119.88	$14,428	$85,829	$621,919
2025	414.1	338.5	75.6	0.000	0.0	$55,797	$4,550	$3,325	$32	$63,703	$9,170	$72,873	$188.22	$121.26	$14,428	$87,301	$677,002
2026	414.1	338.5	75.6	0.000	0.0	$57,074	$4,618	$3,374	$33	$65,099	$9,276	$74,375	$192.34	$122.67	$14,428	$88,803	$730,239
2027	414.1	338.5	75.6	0.000	0.0	$58,341	$4,688	$3,425	$33	$66,487	$9,384	$75,871	$196.44	$124.10	$14,428	$90,299	$781,671
2028	414.1	338.3	75.8	0.000	0.0	$59,275	$4,750	$3,476	$34	$67,534	$9,519	$77,054	$199.66	$125.55	$14,428	$91,482	$831,179
2029	414.1	338.5	75.6	0.000	0.0	$60,610	$4,831	$3,529	$34	$69,004	$9,605	$78,609	$203.88	$127.02	$14,428	$93,037	$879,016
2030	414.1	338.5	75.6	0.000	0.0	$62,020	$4,900	$3,581	$35	$70,536	$9,718	$80,255	$208.41	$128.51	$14,428	$94,683	$925,271
2031	414.1	338.5	75.6	0.000	0.0	$63,439	$4,970	$3,635	$35	$72,080	$9,833	$81,913	$212.97	$130.03	$14,428	$96,341	$969,989
2032	414.1	338.3	75.8	0.000	0.0	$64,803	$5,043	$3,690	$36	$73,571	$9,976	$83,547	$217.50	$131.57	$13,559	$97,106	$1,012,813
2033	414.1	338.5	75.6	0.000	0.0	$66,297	$5,125	$3,745	$36	$75,204	$10,067	$85,271	$222.20	$133.13	$10,954	$96,225	$1,053,133
2034	414.1	338.5	75.6	0.000	0.0	$67,803	$5,199	$3,801	$37	$76,840	$10,187	$87,027	$227.03	$134.72	$10,954	$97,981	$1,092,140
2035	414.1	338.5	75.6	0.000	0.0	$68,865	$5,280	$3,858	$37	$78,041	$10,309	$88,350	$230.58	$136.33	$10,954	$99,304	$1,129,701
2036	414.1	338.3	75.8	0.000	0.0	$70,412	$5,350	$3,916	$38	$79,716	$10,460	$90,176	$235.67	$137.96	$10,954	$101,130	$1,166,046
					Levelized Cost($1000):	$58,680	$4,329	$7,528	$33	$70,571	$6,701	$77,272	$198	$111	$11,050	$88,322	
					NPV:	$774,710	$57,159	$99,390	$434	$931,692	$88,469	$1,020,161	$2,609	$1,466	$145,885	$1,166,046	
					Levelized Cost($/MWh):	$104.82	$7.73	$13.45	$0.06	$126.06	$67.84	$117.31	$124.23	$69.81	$19.74	$134.09	

Notes:

Case 3slr Unit 25 12 month extension VARIABLE only ($3,500 per fired hour)

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions

Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
STT 3 Wartsila 15-yr Lease	39,650	0	15	10/01/2017	40,747	3,474
3x Solar Taurus 70	16,650	6	20	03/01/2018	17,353	1,479
Infrasture Costs (Including T&D)	55,000	1	30	01/01/2019	57,635	4,148
STT 3 Wartsila	25,297	6	20	10/01/2018	26,628	2,270
3x Solar Taurus 70	16,650	6	20	10/01/2019	17,789	1,517
3x Solar Taurus 70	16,650	6	20	10/01/2020	18,055	1,539

	Energy Balance					Production Cost						Total					Cumulative
					Loss		Plant O&M			Total		Production			Unit Additions	Total	Present
				Curtailed	of	Fuel				Generation		Costs plus	Generation		Capital	System	Worth
Year	Load (GWh)	Generation (GWh)	Purchases (GWh)	Load (GWh)	Load Hours	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	Emissions ($1,000)	Cost ($1,000)	Purchases ($1000)	Purchases ($1000)	Cost ($/MWh)	Purchases ($/MWh)	Costs ($1,000)	Cost ($1,000)	Cost ($1,000)
2016	414.1	390.2	23.9	0.000	0.0	$63,249	$1,855	$18,424	$38	$83,566	$2,075	$85,641	$214.15	$87.01	$0	$85,641	$85,641
2017	414.1	387.8	25.8	0.552	93.0	$70,570	$2,425	$19,931	$33	$92,960	$2,110	$95,070	$239.72	$81.87	$869	$95,938	$176,794
2018	414.1	385.5	28.6	0.081	19.0	$57,492	$4,452	$12,565	$35	$74,544	$2,569	$77,113	$193.39	$89.88	$5,275	$82,387	$251,167
2019	414.1	385.5	28.6	0.001	2.0	$46,878	$4,982	$10,800	$26	$62,686	$2,576	$65,262	$162.60	$90.14	$11,751	$77,013	$317,221
2020	414.1	385.5	28.7	0.000	0.0	$55,103	$5,027	$8,354	$27	$68,512	$2,591	$71,104	$177.74	$90.39	$13,273	$84,377	$385,981
2021	414.1	380.6	33.6	0.000	0.0	$56,046	$4,861	$6,055	$33	$66,995	$3,238	$70,233	$176.05	$96.44	$14,428	$84,661	$451,531
2022	414.1	338.5	75.6	0.000	0.0	$51,826	$4,350	$3,674	$31	$59,880	$8,857	$68,737	$176.91	$117.15	$14,428	$83,165	$512,711
2023	414.1	338.5	75.6	0.000	0.0	$53,362	$4,416	$3,227	$31	$61,036	$8,962	$69,998	$180.34	$118.51	$14,428	$84,426	$571,720
2024	414.1	338.3	75.8	0.000	0.0	$54,527	$4,478	$3,275	$32	$62,312	$9,089	$71,401	$184.22	$119.88	$14,428	$85,829	$628,718
2025	414.1	338.5	75.6	0.000	0.0	$55,797	$4,550	$3,325	$32	$63,703	$9,170	$72,873	$188.22	$121.26	$14,428	$87,301	$683,802
2026	414.1	338.5	75.6	0.000	0.0	$57,074	$4,618	$3,374	$33	$65,099	$9,276	$74,375	$192.34	$122.67	$14,428	$88,803	$737,038
2027	414.1	338.5	75.6	0.000	0.0	$58,341	$4,688	$3,425	$33	$66,487	$9,384	$75,871	$196.44	$124.10	$14,428	$90,299	$788,471
2028	414.1	338.3	75.8	0.000	0.0	$59,275	$4,750	$3,476	$34	$67,534	$9,519	$77,054	$199.66	$125.55	$14,428	$91,482	$837,978
2029	414.1	338.5	75.6	0.000	0.0	$60,610	$4,831	$3,529	$34	$69,004	$9,605	$78,609	$203.88	$127.02	$14,428	$93,037	$885,815
2030	414.1	338.5	75.6	0.000	0.0	$62,020	$4,900	$3,581	$35	$70,536	$9,718	$80,255	$208.41	$128.51	$14,428	$94,683	$932,071
2031	414.1	338.5	75.6	0.000	0.0	$63,439	$4,970	$3,635	$35	$72,080	$9,833	$81,913	$212.97	$130.03	$14,428	$96,341	$976,788
2032	414.1	338.3	75.8	0.000	0.0	$64,803	$5,043	$3,690	$36	$73,571	$9,976	$83,547	$217.50	$131.57	$13,559	$97,106	$1,019,613
2033	414.1	338.5	75.6	0.000	0.0	$66,297	$5,125	$3,745	$36	$75,204	$10,067	$85,271	$222.20	$133.13	$10,954	$96,225	$1,059,932
2034	414.1	338.5	75.6	0.000	0.0	$67,803	$5,199	$3,801	$37	$76,840	$10,187	$87,027	$227.03	$134.72	$10,954	$97,981	$1,098,939
2035	414.1	338.5	75.6	0.000	0.0	$68,865	$5,280	$3,858	$37	$78,041	$10,309	$88,350	$230.58	$136.33	$10,954	$99,304	$1,136,501
2036	414.1	338.3	75.8	0.000	0.0	$70,412	$5,350	$3,916	$38	$79,716	$10,460	$90,176	$235.67	$137.96	$10,954	$101,130	$1,172,845
Levelized Cost($1000):						$59,284	$4,393	$7,376	$33	$71,086	$6,701	$77,787	$199	$111	$11,050	$88,837	
NPV:						$782,678	$57,998	$97,377	$438	$938,491	$88,469	$1,026,960	$2,626	$1,466	$145,885	$1,172,845	
Levelized Cost($/MWh):						$105.90	$7.85	$13.18	$0.06	$126.98	$67.84	$118.09	$125.07	$69.81	$19.74	$134.87	

Notes:

Option 0 STX

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions						
Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)

	Energy Balance					Production Cost						Total					Cumulative
					Loss		Plant O&M			Total		Production			Unit Additions	Total	Present
				Curtailed	of	Fuel				Generation		Costs plus	Generation		Capital	System	Worth
Year	Load	Generation	Purchases	Load	Load	Cost	Variable	Fixed	Emissions	Cost	Purchases	Purchases	Cost	Purchases	Costs	Cost	Cost
	(GWh)	(GWh)	(GWh)	(GWh)	Hours	($1,000)	($1,000)	($1,000)	($1,000)	($1,000)	($1000)	($1000)	($/MWh)	($/MWh)	($1,000)	($1,000)	($1,000)
2016	285.5	266.3	16.9	2.24	376.0	$36,860	$11,612	$3,162	$17	$51,652	$1,481	$53,132	$193.94	$87.45	$0	$53,132	$53,132
2017	285.5	258.9	19.6	7.06	452.0	$36,468	$12,208	$2,567	$17	$51,259	$1,506	$52,766	$198.00	$77.01	$0	$52,766	$103,266
2018	285.5	245.8	34.9	4.78	470.0	$38,235	$11,995	$2,779	$17	$53,025	$4,017	$57,043	$215.75	$114.98	$0	$57,043	$154,760
2019	285.5	239.1	43.2	3.22	394.0	$42,527	$12,213	$2,821	$16	$57,578	$5,564	$63,142	$240.80	$128.80	$0	$63,142	$208,917
2020	285.5	236.5	43.3	5.73	673.0	$51,137	$12,580	$2,863	$17	$66,597	$5,606	$72,203	$281.63	$129.44	$0	$72,203	$267,756
2021	285.5	231.3	49.6	4.71	578.0	$52,825	$12,330	$2,906	$17	$68,077	$7,157	$75,234	$294.36	$144.40	$0	$75,234	$326,007
2022	285.5	166.9	117.0	2.25	511.0	$42,220	$8,864	$2,949	$13	$54,047	$23,555	$77,602	$323.81	$201.41	$0	$77,602	$383,094
2023	285.5	167.5	117.0	1.54	469.0	$43,700	$9,017	$2,994	$13	$55,723	$23,595	$79,318	$332.64	$201.75	$0	$79,318	$438,533
2024	285.5	166.2	117.2	2.81	455.0	$44,702	$9,042	$3,039	$14	$56,796	$23,694	$80,490	$341.77	$202.11	$0	$80,490	$491,985
2025	285.5	167.5	117.0	1.73	375.0	$45,886	$9,354	$3,084	$14	$58,339	$23,675	$82,013	$348.37	$202.43	$0	$82,013	$543,732
2026	285.5	166.4	117.0	2.70	513.0	$46,199	$9,351	$3,130	$14	$58,694	$23,715	$82,409	$352.66	$202.78	$0	$82,409	$593,135
2027	285.5	164.6	117.0	4.50	610.0	$47,200	$9,335	$3,177	$14	$59,727	$23,757	$83,483	$362.84	$203.14	$0	$83,483	$640,686
2028	285.5	166.5	117.2	2.44	487.0	$48,053	$9,703	$3,225	$14	$60,996	$23,859	$84,854	$366.25	$203.52	$0	$84,854	$686,606
2029	285.5	166.6	117.0	2.51	448.0	$49,737	$9,801	$3,273	$15	$62,825	$23,841	$86,667	$377.22	$203.86	$0	$86,667	$731,168
2030	285.5	167.1	117.0	1.97	439.0	$51,184	$9,967	$3,323	$15	$64,489	$23,885	$88,373	$385.84	$204.23	$0	$88,373	$774,341
2031	285.5	167.1	117.0	1.99	484.0	$52,018	$10,087	$3,372	$15	$65,492	$23,928	$89,420	$391.98	$204.60	$0	$89,420	$815,847
2032	285.5	166.6	117.2	2.46	530.0	$52,837	$10,258	$3,423	$15	$66,534	$24,033	$90,567	$399.48	$205.01	$0	$90,567	$855,787
2033	285.5	167.2	117.0	1.80	444.0	$53,378	$10,494	$3,474	$15	$67,361	$24,018	$91,379	$402.78	$205.37	$0	$91,379	$894,076
2034	285.5	165.7	117.0	3.47	548.0	$53,921	$10,565	$3,526	$15	$68,027	$24,064	$92,091	$410.44	$205.76	$0	$92,091	$930,739
2035	285.5	166.4	117.0	2.65	503.0	$56,128	$10,645	$3,579	$16	$70,368	$24,111	$94,479	$422.91	$206.16	$0	$94,479	$966,475
2036	285.5	166.1	117.2	2.77	541.0	$57,570	$10,797	$3,633	$16	$72,016	$24,219	$96,235	$433.65	$206.59	$0	$96,235	$1,001,060
					Levelized Cost($1000):	$46,180	$10,668	$3,080	$15	$59,944	$15,882	$75,825	$315	$167	$0	$75,825	
					NPV:	$609,675	$140,841	$40,669	$202	$791,388	$209,673	$1,001,060	$4,163	$2,201	$0	$1,001,060	
					Levelized Cost($/MWh):	$153.33	$35.42	$10.23	$0.05	$199.03	$106.82	$166.97	$198.24	$104.80	$0.00	$166.97	

Notes:

Case 3slr STX - Solar Taurus 70

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions

Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
3x Solar Taurus 70	16,650	6	20	10/01/2018	17,526	1,494
Infrasture Costs (Including T&D)	50,000	1	30	01/01/2019	52,396	3,771
STX 3 Wartsila	25,297	6	20	10/01/2019	27,027	2,304
Solar Taurus 70	5,550	6	20	10/01/2020	6,018	513
Solar Taurus 70	5,550	6	20	10/01/2020	6,018	513
Solar Taurus 70	5,550	6	20	10/01/2022	6,200	529

Year	Energy Balance: Load (GWh)	Generation (GWh)	Purchases (GWh)	Curtailed Load (GWh)	Loss of Load Hours	Production Cost: Fuel Cost ($1,000)	Plant O&M: Variable ($1,000)	Fixed ($1,000)	Emissions ($1,000)	Total Generation Cost ($1,000)	Purchases ($1000)	Total Production Costs plus Purchases ($1000)	Generation Cost ($/MWh)	Purchases ($/MWh)	Unit Additions Capital Costs ($1,000)	Total System Cost ($1,000)	Cumulative Present Worth Cost ($1,000)
2016	285.5	266.3	16.9	2.24	376.0	$36,860	$11,612	$3,162	$17	$51,652	$1,481	$53,132	$193.94	$87.45	$0	$53,132	$53,132
2017	285.5	258.9	19.6	7.06	452.0	$36,468	$12,208	$2,567	$17	$51,259	$1,506	$52,766	$198.00	$77.01	$0	$52,766	$103,266
2018	285.5	245.8	34.9	4.86	500.0	$36,840	$10,222	$2,804	$24	$49,889	$4,017	$53,906	$203.00	$114.98	$374	$54,280	$152,265
2019	285.5	240.0	43.2	2.76	319.0	$33,858	$5,022	$3,235	$41	$42,155	$5,564	$47,720	$175.65	$128.80	$5,841	$53,561	$198,204
2020	285.5	242.2	43.3	0.04	22.0	$36,846	$3,161	$3,604	$28	$43,639	$5,606	$49,245	$180.22	$129.44	$7,826	$57,071	$244,713
2021	285.5	236.0	49.6	0.00	0.0	$36,819	$2,874	$2,647	$29	$42,369	$7,157	$49,526	$179.57	$144.40	$8,596	$58,121	$289,714
2022	285.5	168.6	117.0	0.00	0.0	$27,066	$2,118	$2,696	$19	$31,898	$23,555	$55,453	$189.23	$201.41	$8,728	$64,181	$336,928
2023	285.5	168.6	117.0	0.00	0.0	$27,869	$2,151	$1,668	$19	$31,707	$23,595	$55,302	$188.10	$201.75	$9,124	$64,426	$381,959
2024	285.5	168.3	117.2	0.00	0.0	$28,455	$2,180	$1,693	$19	$32,346	$23,694	$56,040	$192.21	$202.11	$9,124	$65,164	$425,233
2025	285.5	168.6	117.0	0.00	0.0	$29,165	$2,217	$1,718	$19	$33,120	$23,675	$56,795	$196.49	$202.43	$9,124	$65,919	$466,825
2026	285.5	168.6	117.0	0.00	0.0	$29,828	$2,250	$1,744	$20	$33,841	$23,715	$57,557	$200.76	$202.78	$9,124	$66,681	$506,800
2027	285.5	168.6	117.0	0.00	0.0	$30,495	$2,285	$1,770	$20	$34,570	$23,757	$58,327	$205.08	$203.14	$9,124	$67,451	$545,219
2028	285.5	168.3	117.2	0.00	0.0	$30,921	$2,314	$1,796	$20	$35,052	$23,859	$58,910	$208.28	$203.52	$9,124	$68,035	$582,037
2029	285.5	168.6	117.0	0.00	0.0	$31,668	$2,353	$1,823	$21	$35,866	$23,841	$59,707	$212.78	$203.86	$9,124	$68,831	$617,429
2030	285.5	168.6	117.0	0.00	0.0	$32,427	$2,390	$1,851	$21	$36,688	$23,885	$60,573	$217.67	$204.23	$9,124	$69,697	$651,478
2031	285.5	168.6	117.0	0.00	0.0	$33,145	$2,427	$1,879	$21	$37,472	$23,928	$61,400	$222.31	$204.60	$9,124	$70,525	$684,212
2032	285.5	168.3	117.2	0.00	0.0	$33,801	$2,457	$1,907	$21	$38,186	$24,033	$62,219	$226.91	$205.01	$9,124	$71,344	$715,676
2033	285.5	168.6	117.0	0.00	0.0	$34,658	$2,496	$1,935	$22	$39,111	$24,018	$63,129	$232.03	$205.37	$9,124	$72,253	$745,950
2034	285.5	168.6	117.0	0.00	0.0	$35,404	$2,535	$1,964	$22	$39,925	$24,064	$63,990	$236.83	$205.76	$9,124	$73,114	$775,058
2035	285.5	168.6	117.0	0.00	0.0	$35,977	$2,576	$1,994	$22	$40,569	$24,111	$64,680	$240.68	$206.16	$9,124	$73,804	$802,974
2036	285.5	168.3	117.2	0.00	0.0	$36,753	$2,606	$2,024	$23	$41,406	$24,219	$65,624	$246.04	$206.59	$9,124	$74,749	$829,838
					Levelized Cost($1000):	$33,241	$4,538	$2,341	$22	$40,143	$15,882	$56,024	$202	$167	$6,832	$62,856	
					NPV:	$438,862	$59,911	$30,904	$295	$529,971	$209,673	$739,644	$2,664	$2,201	$90,194	$829,838	
					Levelized Cost($/MWh):	$109.27	$14.92	$7.69	$0.07	$131.95	$106.82	$123.37	$126.86	$104.80	$22.46	$138.41	

Notes:

Case 3slrW STX

Financing Parameters	
Bond Interest Rate 30 yr:	5.50%
Bond Interest Rate 20 yr:	5.00%
Bond Issue Fee:	1.50%

Financial Parameters	
Owners Cost, % of EPC	15.5%
Interest During Construction:	5.25%
20 yr Financing Fixed Charge Rate:	8.53%
30 yr Financing Fixed Charge Rate:	7.20%

Economic Parameters	
CPW Discount Rate:	5.25%
Capital Escalation Rate:	1.5%
Base Year for $	2016
General Inflation Rate	1.5%

Generation Additions

Unit	2016 Installed Cost ($1,000)	Construction Period (months)	Financing Life (years)	Date Installed mm/dd/yyyy	Installed Cost ($1,000)	Levelized Cost ($1,000)
3x Solar Taurus 70	16,650	6	20	10/01/2018	17,526	1,494
Infrasture Costs (Including T&D)	50,000	1	30	01/01/2019	52,396	3,771
STX 3 Wartsila	25,297	6	20	10/01/2019	27,027	2,304
Solar Taurus 70	5,550	6	20	10/01/2020	6,018	513
Solar Taurus 70	5,550	6	20	10/01/2016	5,670	483
STX 1 Wartsila	8,432	6	20	10/01/2022	9,421	803

	Energy Balance					Production Cost						Total					Cumulative
					Loss		Plant O&M			Total		Production			Unit Additions	Total	Present
				Curtailed	of	Fuel				Generation		Costs plus	Generation		Capital	System	Worth
Year	Load (GWh)	Generation (GWh)	Purchases (GWh)	Load (GWh)	Load Hours	Cost ($1,000)	Variable ($1,000)	Fixed ($1,000)	Emissions ($1,000)	Cost ($1,000)	Purchases ($1000)	Purchases ($1000)	Cost ($/MWh)	Purchases ($/MWh)	Costs ($1,000)	Cost ($1,000)	Cost ($1,000)
2016	285.5	266.3	16.9	2.24	376.0	$36,860	$11,612	$3,162	$17	$51,652	$1,481	$53,132	$193.94	$87.45	$121	$53,253	$53,253
2017	285.5	258.9	19.6	7.06	452.0	$36,468	$12,208	$2,567	$17	$51,259	$1,506	$52,766	$198.00	$77.01	$483	$53,249	$103,846
2018	285.5	245.8	34.9	4.86	500.0	$36,840	$10,222	$2,804	$24	$49,889	$4,017	$53,906	$203.00	$114.98	$857	$54,763	$153,282
2019	285.5	240.0	43.2	2.76	319.0	$33,858	$5,022	$3,235	$41	$42,155	$5,564	$47,720	$175.65	$128.80	$6,325	$54,044	$199,636
2020	285.5	242.2	43.3	0.04	22.0	$36,846	$3,161	$3,604	$28	$43,639	$5,606	$49,245	$180.22	$129.44	$8,181	$57,426	$246,433
2021	285.5	236.0	49.6	0.00	0.0	$36,819	$2,874	$2,647	$29	$42,369	$7,157	$49,526	$179.57	$144.40	$8,566	$58,092	$291,412
2022	285.5	168.6	117.0	0.00	0.0	$26,800	$2,145	$2,806	$17	$31,767	$23,555	$55,322	$188.46	$201.41	$8,767	$64,089	$338,559
2023	285.5	168.6	117.0	0.00	0.0	$26,968	$2,226	$2,115	$15	$31,324	$23,595	$54,919	$185.83	$201.75	$9,369	$64,288	$383,493
2024	285.5	168.3	117.2	0.00	0.0	$27,553	$2,255	$2,147	$15	$31,970	$23,694	$55,664	$189.98	$202.11	$9,369	$65,033	$426,680
2025	285.5	168.6	117.0	0.00	0.0	$28,216	$2,295	$2,179	$15	$32,706	$23,675	$56,380	$194.03	$202.43	$9,369	$65,750	$468,166
2026	285.5	168.6	117.0	0.00	0.0	$28,864	$2,328	$2,212	$15	$33,420	$23,715	$57,135	$198.25	$202.78	$9,369	$66,504	$508,034
2027	285.5	168.6	117.0	0.00	0.0	$29,504	$2,364	$2,245	$16	$34,128	$23,757	$57,885	$202.47	$203.14	$9,369	$67,254	$546,341
2028	285.5	168.3	117.2	0.00	0.0	$29,931	$2,393	$2,279	$16	$34,619	$23,859	$58,477	$205.71	$203.52	$9,369	$67,846	$583,057
2029	285.5	168.6	117.0	0.00	0.0	$30,653	$2,436	$2,313	$16	$35,418	$23,841	$59,259	$210.12	$203.86	$9,369	$68,629	$618,344
2030	285.5	168.6	117.0	0.00	0.0	$31,360	$2,471	$2,348	$16	$36,195	$23,885	$60,080	$214.75	$204.23	$9,369	$69,449	$652,272
2031	285.5	168.6	117.0	0.00	0.0	$32,063	$2,509	$2,383	$17	$36,972	$23,928	$60,900	$219.34	$204.60	$9,369	$70,270	$684,889
2032	285.5	168.3	117.2	0.00	0.0	$32,713	$2,541	$2,419	$17	$37,689	$24,033	$61,722	$223.95	$205.01	$9,369	$71,092	$716,241
2033	285.5	168.6	117.0	0.00	0.0	$33,508	$2,584	$2,455	$17	$38,564	$24,018	$62,582	$228.80	$205.37	$9,369	$71,952	$746,389
2034	285.5	168.6	117.0	0.00	0.0	$34,274	$2,623	$2,492	$17	$39,406	$24,064	$63,470	$233.78	$205.76	$9,369	$72,839	$775,387
2035	285.5	168.6	117.0	0.00	0.0	$34,824	$2,663	$2,529	$18	$40,034	$24,111	$64,145	$237.51	$206.16	$9,369	$73,514	$803,194
2036	285.5	168.3	117.2	0.00	0.0	$35,566	$2,699	$2,567	$18	$40,850	$24,219	$65,069	$242.75	$206.59	$9,248	$74,317	$829,902
					Levelized Cost($1000):	$32,672	$4,584	$2,612	$20	$39,887	$15,882	$55,769	$200	$167	$7,092	$62,861	
					NPV:	$431,340	$60,513	$34,483	$263	$526,598	$209,673	$736,270	$2,644	$2,201	$93,632	$829,902	
					Levelized Cost($/MWh):	$107.40	$15.07	$8.59	$0.07	$131.11	$106.82	$122.80	$125.91	$104.80	$23.31	$138.42	

Notes:

Appendix B. Modeling Approach and Technical Assumptions

This appendix provides assumptions, inputs, and explanation of methodologies applied in this analysis, as referenced in the main body of this report.

Distributed (Rooftop) Solar PV Assumptions and Methodologies

Rooftop PV potential is based on aerial imagery analysis described in Section 5.2.1. Table B-1 shows the design assumptions applied to the aerial imagery results to estimate the technical potential for rooftop solar PV.

Table B-1 Distributed (Rooftop) Solar PV Design Assumptions

ASSUMPTION	VALUE	NOTES
Roof Coverage Ratio	50%	Amount of roof area available for panel installation. Accounts for obstructions and other features affecting buildability.
Panel Density	6 W/ft^2	Represents average installation, considering various roof pitches and panel spacing.
Minimum Rooftop Area	400 ft^2	To exclude garages and other small buildings without a meter or load.
Maximum System Size	500 kWac	Maximum system size under current feed-in-tariff.

Rooftop PV energy estimates were developed through site modeling using PVsyst software. Standard design assumptions were developed for rooftop systems, to represent a typical rooftop installation. Modeling assumptions are shown in Table B-2. Additional assumptions, particularly system loss specifications, were made based on Black & Veatch's standard distributed solar PV design assumptions and/or calculated based on irradiance and temperature data input to PVsyst.

Table B-2 Rooftop Solar PV Energy Modeling Assumptions

ASSUMPTION	VALUE
Tilt	Fixed tilt at 10 degrees
Azimuth	0 degrees (South facing)
Module Technology	Polycrystalline 310 W modules
Inverter Loading Ratio	1.10
Ground Coverage Ratio	70%
External Shading Loss	5%
Availability Loss	2%

Note: Additional losses, including wiring loss, near shadings, soiling, loss due to temperature, module mismatch, light-induced degradation, module quality, incidence angle modifier, inverter efficiency, and others were developed using Black & Veatch standard design assumptions input to the PVsyst model.

Long term solar irradiance data for USVI is limited. Black & Veatch utilized Meteonorm software's interpolation of local satellite data points to develop irradiance and temperature data input for modeling systems on each of the three islands. In this region, Meteonorm develops hourly irradiance values based on long term monthly data – hours are synthesized using a stochastic model to generate the typical year dataset. This data is reasonable as a high-level estimate of the long term irradiance value, and may also be suitable for project development purposes. However a higher resolution (both spatially and temporally) data set would reduce the uncertainty in this estimate, particularly in the hourly values.

In the Energy Road Map document completed by the Energy Development in Island Nations Group[5] (EDIN; a collaboration between VIWAPA, VI Energy Office, U.S. DOE, U.S. DOI, and NREL), a solar resource map produced by Clean Power Research is presented. This map illustrates the solar irradiance in USVI at a high (approximately 1 km) resolution. Black & Veatch contacted CPR and NREL regarding this data; only the graphical maps were provided by CPR, no supporting data is available. The data used to create this map is an example of that which would likely offer advantage over the Meteonorm data used in this analysis, both in spatial resolution and in resource uncertainty.

Meteonorm has predicted the solar resource to be within approximately 1.5 percent for the three islands – however this is well within the margin of uncertainty for this data source. Practically speaking, the solar resource and resulting energy output can be considered to be approximately equivalent throughout the USVI. Black & Veatch has used the resulting energy estimates and hourly energy output as input to the IRP production cost model; however, detailed resource assessment and long term correlation is recommended for more accurate energy output modeling, particularly at an hourly resolution. NREL and USVI have collected approximately one year of solar insolation data on St. Thomas and St. Croix. Additionally, insolation data has been collected at the operational Toshiba Solar and USVI Solar I sites. This data could be correlated with a high-resolution satellite data set to develop an estimate of the solar resource with greater certainty.

Given the design assumptions in Table B-2 and the annual irradiance data set, Black & Veatch modeled representative rooftop system outputs on each island, shown in Table 5-7 of Section 5.2.1.

Utility-Scale Solar PV Assumptions and Methodologies

To convert the potential solar PV acreages identified in Section 5.2.2 to PV system capacity, Black & Veatch has made general PV system design assumptions, summarized in Table B-3.

Table B-3 Utility-Scale Solar PV Design Assumptions

ASSUMPTION	VALUE
Tilt	Fixed tilt at 10 degrees
Azimuth	0 degrees (South facing)
Module Technology	Polycrystalline 310 W modules
Inverter Loading Ratio	1.35
Ground Coverage Ratio	55%

[5] "USVI Energy Road Map: Charing the Course to a Clean Energy Future", Energy Development in Island Nations, July 2011.

ASSUMPTION	VALUE
Project density: Simple Terrain	5 acres / MWac
Project density: Complex Terrain	8 acres / MWac
Minimum System Capacity (Contiguous Area)	1.0 MWac

Project densities in Table B-3 are based on a fixed-tilt system. This is considered to be the most likely type of design for solar PV development in USVI, however the St. Croix LLC projects, of 3 MW each, are being planned as single-axis tracking (SAT) systems. This type of system requires approximately 40 to 50 percent greater acreage compared to an equivalent fixed tilt system, to accommodate spacing between the tracker rows. The advantage of such a system is greater irradiance capture and increased energy production, estimated to be on the order of 15 percent greater than a fixed-tilt system in USVI. SAT system tracking costs are estimated to be approximately 5 to 10 percent higher than equivalent fixed-tilt designs as shown in Table 5-16 of Section 5.3. While some of the identified simple terrain areas may be suitable for a SAT system, the results of this analysis are based on a fixed-tilt system design.

Utility-scale solar PV energy production was modeled using a very similar approach as the rooftop systems. Together with the Meteonorm satellite data sets for the three islands, standard design assumptions were input into PVsyst modeling software. Utility-scale systems are much more likely to be designed and constructed to achieve negligible external shading, and to achieve higher availability, versus a rooftop distributed solar PV system. Additionally, system design layouts are engineered to achieve optimal land use and system density, and are modeled at a ground coverage ratio typical of ground-mounted, fixed-tilt utility-scale systems. Utility-scale systems typically take advantage of higher inverter loading ratios than distributed systems, to optimize the output profile throughout the day. The design assumptions for utility-scale solar PV system modeling are shown in Table B-4.

Table B-4 Utility-Scale Solar PV Energy Modeling Assumptions

ASSUMPTION	VALUE
Tilt	Fixed tilt at 10 degrees
Azimuth	0 degrees (South facing)
Module Technology	Polycrystalline 310 W modules
Inverter Loading Ratio	1.35
Ground Coverage Ratio	55%
External Shading Loss	0%
Availability Loss	1%

Note: Additional losses, including wiring loss, near shadings, soiling, loss due to temperature, module mismatch, light-induced degradation, module quality, incidence angle modifier, inverter efficiency, and others were developed using Black & Veatch standard design assumptions input to the PVsyst model.

As discussed previously in this section, there are limitations due to the resolution of the solar irradiance data used to model solar PV energy output in this analysis; however, the data should provide a reasonable and useful estimate of the annual irradiance for energy estimating purposes.

Given the design assumptions in Table B-4 and the annual irradiance data set, Black & Veatch modeled representative system outputs on each island. Modeling results are shown in Table 5-11 of Section 5.2.2.

Utility-Scale Wind Assumptions and Methodologies

Black & Veatch estimated technical potential for utility-scale wind projects using a GIS-based method as outlined in Section 5.2.3. The development of that potential is based on assumptions of wind turbine characteristics shown below in Table B-5.

Table B-5 Utility Scale Wind Turbine Characteristics

	VESTAS V100	VERGNET GEV MP C
Nameplate Rating (kWac)	1800	275
Modeled Hub Height (m)	80	55
Rotor Diameter (m)	100	32

Black & Veatch utilized the wind flow modeling results developed by NREL and AWS Truepower to inform the layout creation. Minimum turbine separations were based on the measured wind rose which exhibits a prevailing ESE direction. Wind mapping results were used to identify locations of most promising resource within the identified areas. In creating the layouts, some smaller and/or more distant pieces of land were excluded, particularly if those areas showed relatively poor wind resource. In that respect, these layouts should provide a conservative but realistic representation of wind project development, though any real wind project development should rely on careful modeling and micrositing to determine a truly buildable layout.

Figure B-1 shows an example of the layout creation process for some of the turbines in Site 2. In this image the pink shapes are the areas meeting the exclusion criteria, against the estimated net capacity factor map (discussed below).

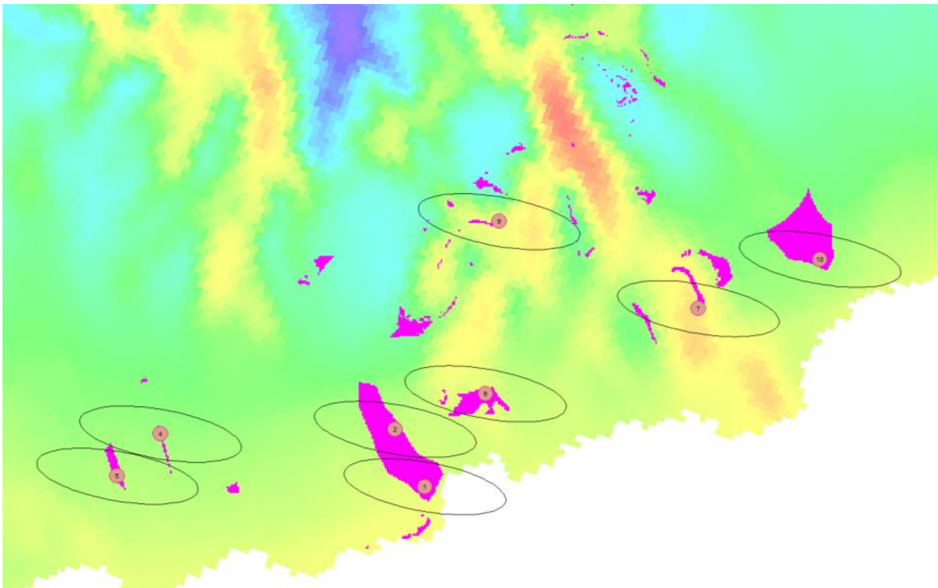


Figure B-1 Example Wind Turbine Layout Creation

NREL and AWS acknowledge significant differences in the wind speeds predicted by the wind flow model with those measured at Bovoni and Longford. NREL also acknowledges the high uncertainty in extrapolating the measured data at Bovoni beyond the met tower location. These discrepancies are not unusual for complex terrain regions. Additionally, NREL and AWS come to fairly different conclusions with regard to long term adjustment of the measured and modeled data sets. For any utility-scale wind development, a robust resource assessment campaign utilizing multiple met towers, ideally over a multiple-year period, is recommended to reduce the uncertainty in the long term wind speed and resulting energy estimates. For the purposes of this analysis, Black & Veatch has elected to utilize the AWS wind map, to provide a consistent resource estimate across the islands. The resulting energy estimates are only preliminary values to provide a high level understanding of the potential energy generation.

To translate those modeled wind speeds to energy output, Black & Veatch has applied the power curves for the turbines assessed in Section 5.2.3: the Vestas V100 1.8 MW at an 80-meter hub height, and the Vergnet GEV MP C 275 kW at a 55-meter hub height. Figure B-2 shows a representative wind speed distribution for the Bovoni region as an example, against the Vestas V100 power curve.

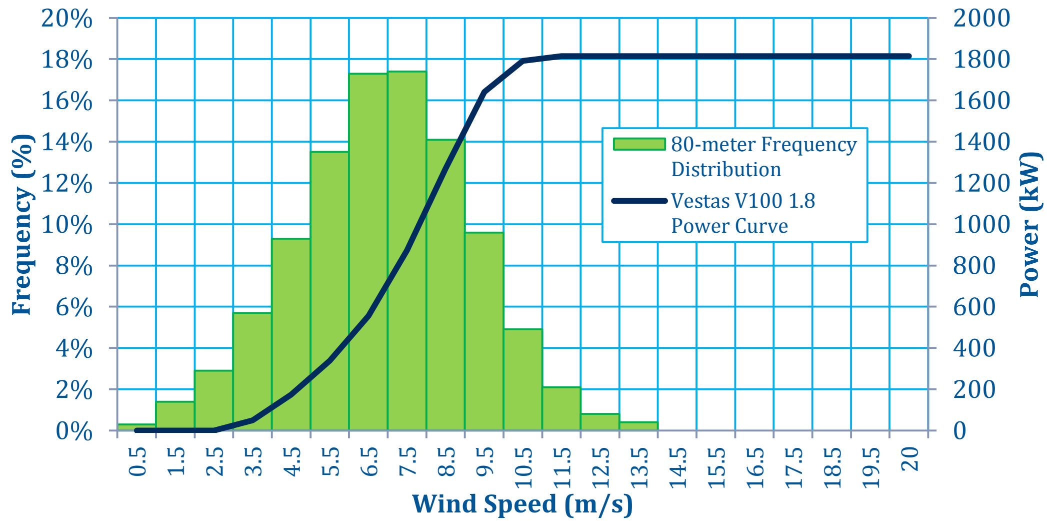


Figure B-2 Bovoni Wind Speed Distribution and V100 Turbine Power Curve

To estimate net energy output, Black & Veatch has assumed standard gross-to-net loss assumptions. These losses, shown in Table B-6, are representative of a multi-turbine wind farm in USVI, however detailed losses (particularly wake effects), should be modeled or calculated for any project development, on a site-specific basis.

Table B-6 Wind Energy Loss Assumptions

LOSSES	%
Wake from neighboring turbines	8.0
Turbine Availability	4.0
Utility Downtime / BOP	0.5
Operational Electrical Efficiency	3.0
High Wind Hysteresis Effect	0.0
Performance degradation - icing	0.0
Performance degradation - non-icing	0.5
Icing Shutdown	0.0
High Temperature Shutdown	0.5
Extreme Weather Shutdown	1.0
Turbine power curve performance	2.0
Total Loss	**18.0**

Black & Veatch applied the gross-to-net losses to the gross energy calculated from the AWS wind map distributions at both 80-meter and 55-meter hub heights to produce a net capacity factor wind map for the islands. Black & Veatch then assigned the calculated NCF values for the associated turbine locations from the layouts developed in Section 5.2.3. Figure B-3 shows the calculated NCF map of St. Croix, for the Vestas V100 turbine at an 80-meter hub height, together with the preliminary turbine layouts. The resulting energy estimates are shown in and Table 5-14 and Table 5-15 of Section 5.2.3.

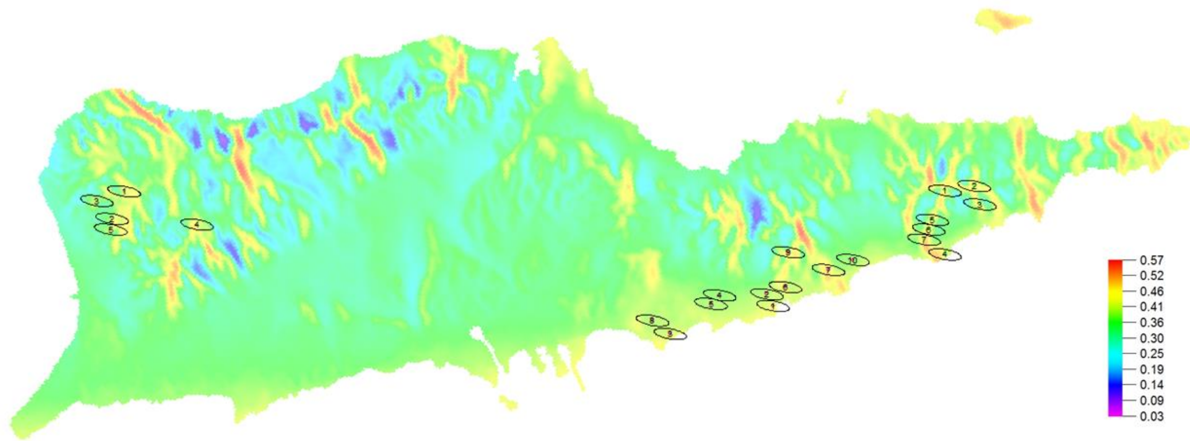


Figure B-3 Wind Energy NCF Map of St. Croix with Potential Turbine Locations (Vestas V100)

Appendix C. Additional Renewable Energy Potential

In addition to the existing, planned, and potential projects discussed in Sections 5.1 and 0, Black & Veatch notes that other renewable project potential may exist. Black & Veatch has conducted a high level analysis of these resources, presented in the following sections; however these resources and projects are not otherwise incorporated into the IRP planning or the production cost model.

Waste-to-Energy

Waste-to-energy (WTE) may be an attractive option for future baseload electricity generation in USVI, and would also offer a waste management solution as the existing landfills on St. Thomas and St. Croix reach their capacities. NREL completed a thorough evaluation of WTE options on USVI in 2011[6]. There have been previous proposals for a WTE plant in USVI on the order of 10 to 15 MW, one of which is referenced in the NREL study. Currently there is no active WTE project development in USVI.

WTE projects are often associated with more negative environmental impacts than other renewable technologies like solar, wind, and biomass. However, as NREL also concludes in their report, WTE can provide an overall environmental benefit particularly in a location like USVI where waste management presents a challenge.

NREL investigated several WTE technology options, focusing on refuse-derived fuel (RDF) combustion and RDF gasification, as well as aggressive recycling and composting programs. Based on their analysis, an RDF WTE plant on USVI could generate 13 MW of baseload generation, and provide a significant environmental benefit versus the current landfill operations.

Landfill Gas

The Bovoni Landfill currently has a proposed 1.5 MW Landfill Gas (LFG) project, to begin operation in 2016. Based on a review of the resource data provided in the U.S. EPA's Landfill Methane Outreach Program (LMOP) database, there would likely not be potential for any additional generation beyond the planned 1.5 MW at Bovoni. The Anguilla Landfill, on St. Croix, is an older and larger landfill than Bovoni. LMOP shows this landfill as a candidate site, however there is not a gas collection system currently in place according to LMOP. This location may offer an opportunity for LFG project development of approximately 1 to 2 MW based on the LMOP estimated waste in place (Aguilla Landfill is still accepting waste, though LMOP shows it to be closed in 2010). LFG can also be used as an alternative thermal energy source in other applications, including refinement for use in RNG vehicles.

VIWAPA and the Virgin Islands Waste Management Authority (VIWMA) have indicated there are no current plans for LFG project development at Anguilla.

Biomass

The Tibbar Energy project is planned to begin operation in 2017, utilizing digestion of Giant King Grass feedstock, grown at the project site, with the digester gas fed to engine generators to produce approximately 8 MW of baseload power. There are no other biomass projects planned on USVI,

[6] "Waste-to-Energy Evaluation: U.S. Virgin Islands", National Renewable Energy Lab, August 2011.

however if the Tibbar project proves successful this may spur additional development of biomass energy projects at other locations throughout USVI.

Black & Veatch did not conduct a biomass resource assessment as part of this analysis, though there does not appear to be significant sources of biomass byproduct available as feedstock for a utility-scale biomass energy plant (forestry residues, urban wood wastes, food wastes, etc). This would imply the need for feedstock growth on the islands, similar to the Tibbar project. Based on the Tibbar planned crop acreage, a project utilizing similar technology would require approximately 220 acres per MW of capacity. Land use requirements would likely be similar to the simple terrain utility-scale solar areas, potentially with additional setbacks or exclusions for engine operation and air emissions.

Using the land area identified in the utility solar PV potential analysis as a high-level proxy, there is likely limited potential for additional biomass generation, with only a two areas identified (both on St. Croix) with contiguous areas greater than 200 acres.

Offshore Wind

Offshore wind is a developing industry, with virtually no operating project experience in the U.S., but with many successful projects operating internationally. Current installed costs for offshore projects are typically significantly higher than they are for onshore projects (upwards of three to five times the cost of onshore projects[7]), and offshore development is generally driven by the absence of feasible areas for onshore projects. Several major manufacturers, including Vestas/Mitsubishi, GE, Siemens, and others offer wind turbines designed specifically for offshore applications, often at relatively large capacities (some 5 MW and greater) and with a number of site-specific foundation and hub height options.

There may be potential for offshore wind on USVI, particularly if onshore projects prove infeasible and additional renewable generation is needed in the future. Currently, there appear to be some promising options for onshore development; these projects would be preferred over offshore wind projects in USVI.

The AWS Truepower wind map was geographically constrained to the USVI land area, and there is no other known data available to estimate the offshore wind resource in USVI. To determine the potential for this technology, it is recommended that the proper data be collected to determine the wind resource and the suitability for turbine installation in the waters surrounding USVI.

Ocean Thermal

Ocean Thermal Energy Conversion (OTEC) technology utilizes the temperature difference between the ocean's surface and deep water to generated electricity by way of a Rankine cycle power system. Generally speaking, OTEC is most promising in regions with warm surface temperatures and greater ocean depths, which provide the greatest system efficiencies. While the concept has been proven to be technically viable in smaller demonstration projects (<1 MW), the key challenge has been to implement a design that is not only technically feasible but is attractive from a

[7] "2014-2015 Offshore Wind Technologies Market Report", National Renewable Energy Lab, September 2015.

commercial and economic viewpoint. Given the suitable water temperatures and depths around USVI, and the relatively high electricity prices, OTEC may be an interesting technology to consider.

Ocean Thermal Energy Corporation (OTE) has completed a techno-economic feasibility study commissioned by USVI[8], which focuses on the conceptual design of a 5 to 7 MW land-based plant on St. Croix near Rust-op Twist, and a 10 to 15 MW floating platform plant offshore on the Southeast side of St. Thomas. OTE has also evaluated the integration of a reverse osmosis (RO) freshwater supply system powered by the OTEC plant. While this reduces the total energy delivered to the grid, the overall project economics are improved due to the value of the fresh water.

OTE's analysis includes a preliminary economic analysis including estimates of capital and O&M costs. For the on-shore project, OTE also provides "expected electricity price" estimates at various internal rates of return (IRR). These estimates are summarized below in Table C-1. It is noted that Black & Veatch has not reviewed any details of the theoretical or numerical calculation or simulation conducted by Ocean Thermal Energy Corporation.

Table C-1 Summary of OTE Cost Estimates

DESIGN	PROJECT SIZE (KW AC)	CAPITAL COST ($/KW AC)	FIXED O&M COST ($/KWAC-YR)	"EXPECTED ELECTRICITY PRICE"(1)
2-Stage On-shore	7,430	30,900	270	$0.33
2-Stage Off-shore	14,710	26,600	305	NA

All values are as estimated by Ocean Thermal Energy Corporation.

(1) Corresponds to an IRR of 10%, without incorporation of freshwater sales. OTE estimates a price of approximately $0.20/kWh when incorporating freshwater sales.

Capital and O&M costs estimated by OTE are considerably higher than the other renewable energy resources evaluated in this report. An OTEC plant is expected to achieve a very high capacity factor, operating essentially as baseload generation, and as such the most appropriate comparison with other generation sources would be in terms of LCOE. Black & Veatch developed LCOE estimates for those technologies shown in Table 5-16, for the production cost modeling performed as part of the larger IRP study. At $0.33/kWh (OTE's estimate at a 10 percent IRR, without incorporating freshwater sales), the OTEC energy would be about twice the estimated cost for utility-scale solar PV, and about triple the estimated cost for utility-scale wind. Incorporating freshwater sales could improve the economics considerably; OTE estimates $0.20/kWh (10 percent IRR) in that case.

The OTEC concept has evolved over the years, and it is feasible, yet unproven at this scale. USVI may be a promising candidate to pioneer this technology if there is tolerance for some uncertainty in actual cost and performance.

[8] "Draft OTEC Feasibility Study for the U.S. Virgin Islands", Ocean Thermal Energy Corporation, September 2015

Appendix D. Levelized Cost of Energy Assumptions

Levelized cost of energy estimates were developed for input to the production cost modeling performed as part of the larger IRP study. In addition to the cost data presented in Table 5-16 of Section 5.3, Black & Veatch applied the following financial assumptions as input to the LCOE calculation, shown in Table D-1.

Table D-1 LCOE Financial Assumptions

LCOE INPUTS	VALUE
WACC	8%
ITC (Solar)	10%
PTC (Wind)	0%
Project Life (Years)	25
5 Year MACRS	Applied to all Projects
Energy Value Escalation	2%
O&M Escalation	2%